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THE POTENTIAL FOR ENERGY SUBSTITUTION IN CANADA

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PREFACE

The Canadian Energy Research Institute (CERI) is a co-operative research organization sponsored by five parties: Energy, Mines and Resources Canada, the Alberta Department of Energy and Natural Resources, the Private Energy Research Association (composed of corporate and individual members from oil, gas, coal, electrical, nuclear energy and pipeline companies), The University of Calgary and the Ontario Ministry of Energy. The objectives of the Institute are to develop an economic research capability and to conduct studies that will assist industry and government in dealing with energy problems. The research programme of the Institute is developed by a Board of Directors named by the sponsoring organization. The content of the individual studies is, however, the responsibility of the authors.

In addition to undertaking studies in energy economics funded collectively by the five Institute sponsors, CERI carries out research for clients on a contractual basis.

This working paper is the first of two papers which will collectively address the inter-dependent subjects of inter-fuel substitution and energy conservation. This first paper investigates the extent to which inter-fuel substitution could occur in Canada over the 1984-1990 period.

EXECUTIVE SUMMARY

One major objective of the National Energy Program is to reduce the use of petroleum products to no more than ten percent of total energy use in each of the residential, commercial and industrial sectors in Canada by 1990. This may be a difficult task because petroleum products accounted for almost 27 percent of all industrial energy use, 25 percent of all commercial energy use and almost 45 percent of all residential energy use in 1980. The transportation sector was then almost totally dependent (96 percent) upon petroleum products.

This paper makes use of Mace, an econometric model of the Canadian economy, to forecast the extent to which inter-fuel substitution is likely to occur amongst the four major primary energy sources in Canada: coal, crude oil, natural gas and electricity. Recent moderation in the upward trend of oil prices has tended to slow down the substitution of coal, gas and electricity for crude oil products, although substitution is still an economically attractive alternative in many cases of energy use.

Forecasts of inter-fuel substitution generated in this report are based upon the assumptions that energy markets continue to be regulated until 1990 and that the various incentives and subsidies (e.g., the 65 percent commodity equivalent rate for the price of natural gas) remain intact.

The results presented here show that under a 'most likely' oil price scenario for the period 1985 to 1990, the national market share held by crude oil falls from 33 percent to 30 percent, in spite of an increase in the absolute demand for oil by 9 percent during this period. Conversely, natural gas gains the 3 percent share lost by oil, moving from 33 percent in 1985 to 36 percent in 1990. The shares of coal and primary electricity remain at 7 and 27 percent, respectively.

The National Energy Program "Update 1982" predicted increased shares of the total primary energy market for both coal and electricity by 1990. Under a much lower oil price scenario natural gas gains an extra 5 percent of the market (due to the 65 percent rule) at the expense of both oil and electricity. Under this low oil price scenario consumers utilize refined petroleum products for incremental energy supplies, rather than electricity or coal.

Forecasts of inter-fuel substitution are provided for three oil price scenarios in which the 75 percent price cap on old oil is assumed to be removed in 1984. In the 'most likely' case, demand for crude oil is lower by 2 percent in relation to the same case with the price cap intact. As may be expected, total energy consumption is reduced under all three scenarios with the price cap removed. Under this scenario there are no significant changes in the market shares.

The paper also contains a discussion of unconventional alternatives to the four main energy sources such as propane, wood, solar energy, and alcohol fuels. Although substitution of alternative fuels has been slow in the transportation sector, there have been many conversions under the Canadian Oil Substitution Program. Wood, in particular, has become popular as a space heating fuel with some 130,000 conversions under the program to date. Conversions to other alternatives, such as solar heat, have been few--about 0.2 percent of the total.

While there has already been significant inter-fuel substitution in Canada, the potential exists for more to occur. The substitution motive would be enhanced by a pricing policy which forces consumers to pay the full opportunity cost for oil, i.e., if the domestic oil prices were taken to the world price. This is even more true now that it appears that world oil prices will generally be lower through the next decade than most forecasters were projecting in 1980.

Chapter 1

INTRODUCTION

A major objective of the National Energy Program (NEP) is to encourage substitution of more abundant domestic sources of energy for imported and domestic crude oil.[1] In order to accomplish this objective, various government incentives have been provided which, in combination with higher real oil prices relative to other energy prices, could be expected to bring about a significant change in the relative market shares of all energy forms. By 1990, a large shift towards natural gas--domestically an abundant fuel--and to a lesser extent towards coal and electricity is envisaged by the NEP.[2] However, whether the inter-fuel substitution goal proclaimed by the program can be reached within the time frame given is uncertain.

The purpose of this analysis is to investigate the degree to which inter-fuel substitution will occur in Canada over the 1983-1990 period, given the energy pricing developments of 1982-1983. A final phase of the analysis, to be published under separate cover, will compare the roles of both energy conservation and inter-fuel substitution. A major objective of the study is to quantitatively evaluate the potential effects on inter-fuel substitution of softer oil prices. This is done with the aid of Mace, an econometric model which can forecast future levels of consumption of energy from conventional sources, such as petroleum products, natural gas, electricity and coal, given changing relative prices.

Chapter 2 contains a brief review of the theoretical formulations which form the basis for the analysis. Chapter 3 reviews the Canadian energy market and identifies the trends in consumption established during the 1970s. Chapters 4 and 5 are focused on demand projections for the four major conventional fuels under various price scenarios. These

compose virtually all of Canada's current primary and secondary energy demand and will remain prominent until well into the next century. Chapter 6 contains a review of the potential for unconventional alternatives as substitutes for refined petroleum products. Chapter 7 summarizes the combined potential for oil substitution by the conventional and unconventional alternatives.

Footnotes

[1]Canada, Department of Energy, Mines and Resources Canada, The National Energy Program 1980, Report EP-4E (Ottawa: Supply and Services Canada, 1980), p. 54.

[2]Ibid., p. 100.

Chapter 2

ENERGY SUBSTITUTION DEFINED

Because various types of substitution can occur in energy consumption, it is essential to define 'oil substitution' at the outset and to clearly state what it means in the context of this study. Basically, three types of substitution can be identified. The first involves replacement of imports of foreign oil with indigenous supplies. In this regard, Canada's proven conventional oil reserves are declining and oil from non-conventional sources, such as oil sands and heavy oil deposits and frontier regions will become increasingly important. However, non-conventional sources of oil, including frontier development will require a much greater commitment of resources and time. Consequently, oil production from many of these sources will be economic only at higher domestic oil prices and/or lower taxes.

A second type of energy substitution which may occur can be explained with reference to the mix of inputs used in industrial production. Mathematically, such a mix can be specified in a typical aggregate production function showing how the various inputs are combined to produce a given output. A production function can be written as follows:

$$Q = f\,(K,L,E\,(f_1,f_2,f_3,f_4),M)$$

where Q represents output,
K represents capital inputs,
L represents labour inputs,
E is a function of individual fuels, and
M represents material inputs.

This function indicates that four types of inputs: capital, labour, energy and materials, are combined by the firm in such a way that some quantity of output is produced. It also assumes that the firm may make use of different types of energy to provide the required energy input.

It is usually the case that, to some extent, the proportions of the inputs employed in production can be altered. Furthermore, it is assumed that the inputs are combined in such a way that the input cost of production is minimized for a given level of output. This means that if the services of capital become expensive relative to labour, the firm will use relatively more labour, less capital, and vice versa. Movements of relative prices of inputs imply that an adjustment in the amounts of inputs used will be made. This second type of substitution, referred to above, is sometimes considered to be 'energy conservation'. Actually, it is more illuminating to say that 'non-energy' inputs (now relatively less expensive) are being substituted for energy inputs. Implicitly, this assumes energy and other inputs to be substitutes (at least to some extent) rather than complements.

In Canada, energy prices have historically been low in comparison to other countries. It has, therefore, often been very reasonable to choose more energy-intensive production processes. This must be acknowledged as being one of the primary reasons for the high level of energy use per unit of domestically produced goods and services in Canada in relation to other countries where energy prices have historically been higher and demand lower.[1] With the recent rapid escalation in real energy prices it is expected that industrial and commercial production will become less energy-intensive and more capital, labour and material-intensive.

Although the above discussion refers specifically to the industrial use of energy, a similar substitution effect can occur in other final-use sectors. Consumers generally act to maximize their total satisfaction or utility. Higher energy prices in relation to other consumer goods and services imply that relatively smaller amounts of energy will be used. For example, consumers may purchase less gasoline to drive more fuel-efficient cars, but increase expenditures on recreation.

In a general sense, substitution away from energy towards other inputs and goods and services could be expected across the entire economy in response to real energy price increases. One way to evaluate the extent of this type of

substitution is to determine the change in the ratio of total energy use to Gross Domestic Product (GDP) over time. This will be discussed in greater detail in Chapter 3.

The third type of oil substitution, and the focal point of most of the analysis of this paper, is inter-fuel substitution. In the production function given above, the energy component is a function of different types of fuel. In most modern industrial economies, the major fuels are refined crude oil products, natural gas, coal and electricity. A firm fuelling its plant or a householder heating his home may choose from among the available fuels and select the one which provides the required service at lowest cost. In order to produce space heating or process heat, any energy source which produces heat is suitable. Liquid, solid or gaseous fuels can be burned to produce heat, or electricity can be run through a high resistance circuit to produce heat. For such purposes, any of these fuels may be close, or in some cases perfect substitutes, depending upon the ability to switch the capital equipment from one fuel to another.

In reality, fuel use is generally closely tied to the type of capital equipment in place. Once oil-burning equipment is installed in a plant, alternative fuels cease to be viable substitutes until that equipment is due for replacement or the price differential between fuels becomes large enough to justify modification. In Canada, significant substitution of oil with natural gas cannot occur until capital equipment tied to oil use is replaced or modified. Only a small portion of capital equipment can be easily switched back and forth between fuels without extra investment.

The degree of substitutability between fuels is thus limited, at least in the short run, by installed energy-using capital equipment. In the long run, substitutability can be increased as older capital stock can be replaced with equipment capable of using different fuels, or a variety of fuels.

Energy, however, is not used solely for its ability to produce heat. Large amounts of energy are used to generate mechanical motion, operate electronic equipment, and refine and smelt metallic ores through electro-reduction.

Clearly, only some forms of energy are appropriate for use in these modes. Only electricity can be used to run electrical motors or computers or smelt aluminum. Alternatively, in the transportation sector, only liquid or gaseous fuels are presently in use to power modern vehicle engines. In the short run it is not practical to substitute electricity for conventional fuels in most transportation uses. However, this may not be true over longer periods of time when technological advances may make electric vehicles, or other alternatives viable. In general, the inter-fuel substitution potential may be limited by the characteristics peculiar to a given task which energy is called upon to perform, and upon the availability of alternatives.

While only one form of energy may be appropriate for a particular use, energy consumers may often have more than one option when choosing amongst fuels. The ability to substitute one fuel for another when relative prices change may be found to be significant in most areas of Canada but it varies from region to region and from sector to sector. Although virtually all energy consumers are in close proximity to electricity supply, in some areas (notably eastern Quebec, the Atlantic provinces and the Territories) a natural gas distribution infrastructure currently does not exist, precluding substitution of natural gas in place of oil. Differences in fuel availability and in relative prices across Canada have resulted in marked regional differences in the market shares of each energy type.

Footnotes

[1]For example, see Z. C. Slagorsky, Energy Use in Canada in Comparison With Other Countries, Study No. 8 (Calgary: Canadian Energy Research Institute, October 1979).

Chapter 3

PAST ENERGY PRICING AND CONSUMPTION TRENDS

The history of energy consumption and production in Canada in the 1970s, along with the historical trend in energy prices has been well documented in other studies. However, a brief review of the consumption and inter-fuel substitution trends established in Canada over the decade will be useful in gaining a perspective on the types of substitution which have occurred and where the greatest potential for substitution lies.

In Chapter 2, it was mentioned that two types of substitution would be of interest to this study. The first involves the substitution of non-energy inputs for energy inputs. The second involves inter-fuel substitution. The following discussion will deal first with empirical evidence of non-energy substitution and then with inter-fuel substitution.

3.1 The Energy/GDP Ratio

Some evidence of substitution between energy inputs and non-energy inputs in various countries is implied by movements in their E/GDP ratio.

Recent research into the total energy (E) to gross domestic product (GDP) ratio for some of the Organization for Economic Cooperation and Development (OECD) countries has shown that significant differences in the ratio exist, both across countries and over time. Griffin observed that within a sample of 18 OECD countries in 1973 the ratio varied from a low of 30.0 (10^3 Btu/$) in Norway to a high of 75.0 (10^3 Btu/$) in Canada.[1] Although some researchers have attempted to classify countries with high ratios as 'wasteful' and countries with low ratios as 'energy efficient', most researchers attribute differences in the ratio from country to country and over time to an array of different factors.

Griffin identifies six factors which help explain these differences.[2]

1. The calculation of GDP for each country on the basis of a common currency (e.g., the U.S. dollar) involves adjustments using international exchange rates--but these do not reflect the prices of goods which are not traded on the world market.

2. There are vast differences in the importance of a given sector of the economy across various countries. The industrial sector, for example, may account for a larger share of GDP in the United States than it does in France. Furthermore, the industrial structure may be different from country to country accounting for different levels of energy use.

3. The E/GDP ratio can vary if the mix of fuels is different from country to country. In order to obtain an estimate of total energy used, expressed in common units such as millions of tons of oil equivalent, different fuel types with different conversion factors must be lumped together. If one country makes use of large amounts of a fuel which has a low conversion efficiency, its use of primary energy will be much higher on an input Btu basis than a country which uses a more efficient fuel.

4. The relationship of energy prices to non-energy prices will largely affect the E/GDP ratio through the process discussed in Chapter 2. Uniformly low energy prices will encourage relatively energy-intensive production processes, while a general upward movement in energy prices will induce a movement to substitute other inputs in place of energy.

5. Technological change may improve the conversion factors thus reducing the number of input joules (or Btu) required to produce one output joule (or Btu) of energy. This type of technological advance may require a number of years to occur and in some cases may only occur over the long run.

6. Changes in the E/GDP ratio may also result from a general economic slowdown and, if so, may be only temporary aberrations.

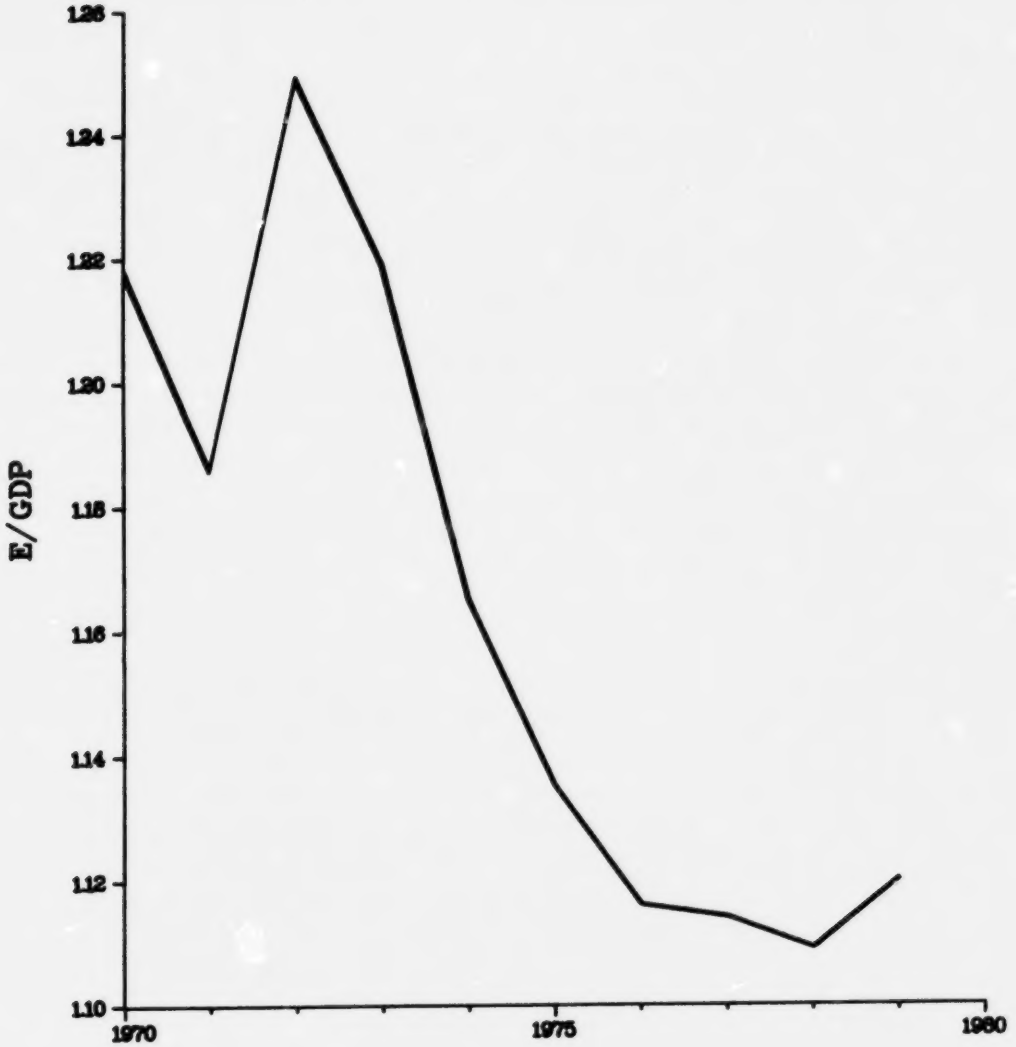
Other factors which are important are climate, distances, life style, per capita income and natural resource extraction.

Figure 3.1 shows the movement of the E/GDP ratio for Canada from 1970 to 1979, the latest year for which OECD data are available. The ratio reached its peak in 1972 at 1.249 and declined as the decade progressed. By 1978, the ratio had reached a low of 1.109. Clearly, a significant decline in energy use per dollar of GDP had occurred (11% from 1972 to 1978). It seems likely that, in the light of rising real energy prices, some of the decline in the ratio noted in Figure 3.1 was brought about by non-energy substitution. While energy prices continued to climb in real terms, 1979 marked an abrupt reversal of the trend, the opposite of what would be expected. (The reader should be careful to note that the scale of the vertical axis in Figure 3.1 is calibrated in very small increments.)

Following real energy price increases, it would be expected that the E/GDP ratio would decline further as other inputs are substituted for energy in production and other goods and services are substituted for energy in consumption. It should be noted that there is no ideal E/GDP ratio since the prices of all inputs will vary across countries and also over time, and that technological conditions of production will also not remain constant.

3.2 Energy Pricing

Although energy use in any given economy is tied to the level of GDP, climate, geography, density of population and other factors, individual energy prices are very important in determining the quantity of energy demanded. In Chapter 2 it was suggested that price differentials between energy and other inputs were most important in determining the overall mix of inputs selected. Movements in relative prices will usually bring about an adjustment in the amounts of inputs used. This also holds true for the different energy types. Real price differentials between competing fuels suggest that relatively more of the less expensive fuel will be used.[3]



Note: E is Millions of Tons of Oil Equivalent.
GDP is Gross Domestic Product.

Source: Organization For Economic Cooperation and Development, (O.E.C.D.), National Accounts of O.E.C.D. Countries, 62–79, Volume 2, Paris, 1981, p. 7, and Energy Balance of O.E.C.D. Countries, Paris, 1979.

Figure 3.1: Total Energy Per GDP Ratio in Canada

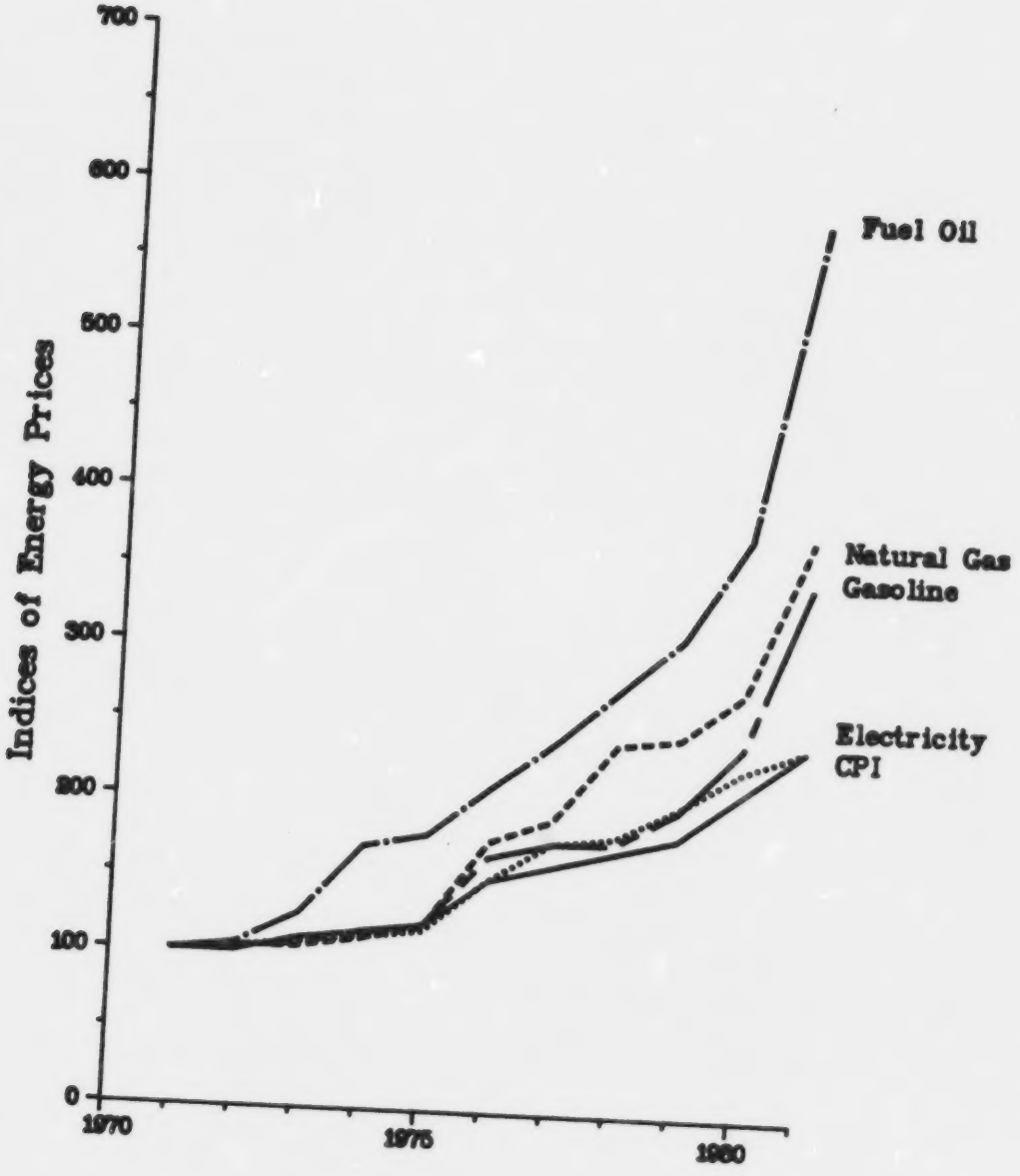
Statistics Canada price indices are shown in Figures 3.2, 3.3 and 3.4 to illustrate the relative movements of various consumer and industry energy prices in relation to the Consumer Price Index (CPI) and the Industrial Selling Price Index (IPI) since 1971. Figure 3.2 compares the movement of Canadian consumer energy prices with the CPI. It should be noted that these indices do not show the absolute differential between the various energy prices. Although electricity, gasoline, and natural gas prices closely tracked the CPI during the first half of the 1970s (denoting no significant real price increase), the prices of home heating fuels, natural gas and fuel oil rose rapidly in real terms after 1975. Gasoline prices tracked the CPI closely until 1980.

Figure 3.3 shows the movements of some industrial energy prices in relation to the IPI. Thermal coal experienced a significant real price increase over the period 1973-1980. However, electricity prices where demand is under 5 megawatts did not keep pace with the IPI over the entire period. Electricity prices where demand is greater than 5 megawatts failed to keep up with the IPI until 1977 after which real gains were made until 1980.

Figure 3.4 shows the movement of industrial refined petroleum product prices in Canada. All fuels made significant gains in real terms from 1974 on. Heavy fuel oil prices rose by approximately 700 percent from 1971 to 1981 while, on average, the lighter fractions rose in price by 450 percent.

Figures 3.2, 3.3 and 3.4 show that the various prices, both consumer and industrial, have not moved evenly. The refined petroleum products prices had increased the most by 1981; natural gas and coal prices also increased significantly, but by a relatively smaller amount. Electricity prices in both consumer and industrial markets recorded only very small real increases and in one case a real price decrease.

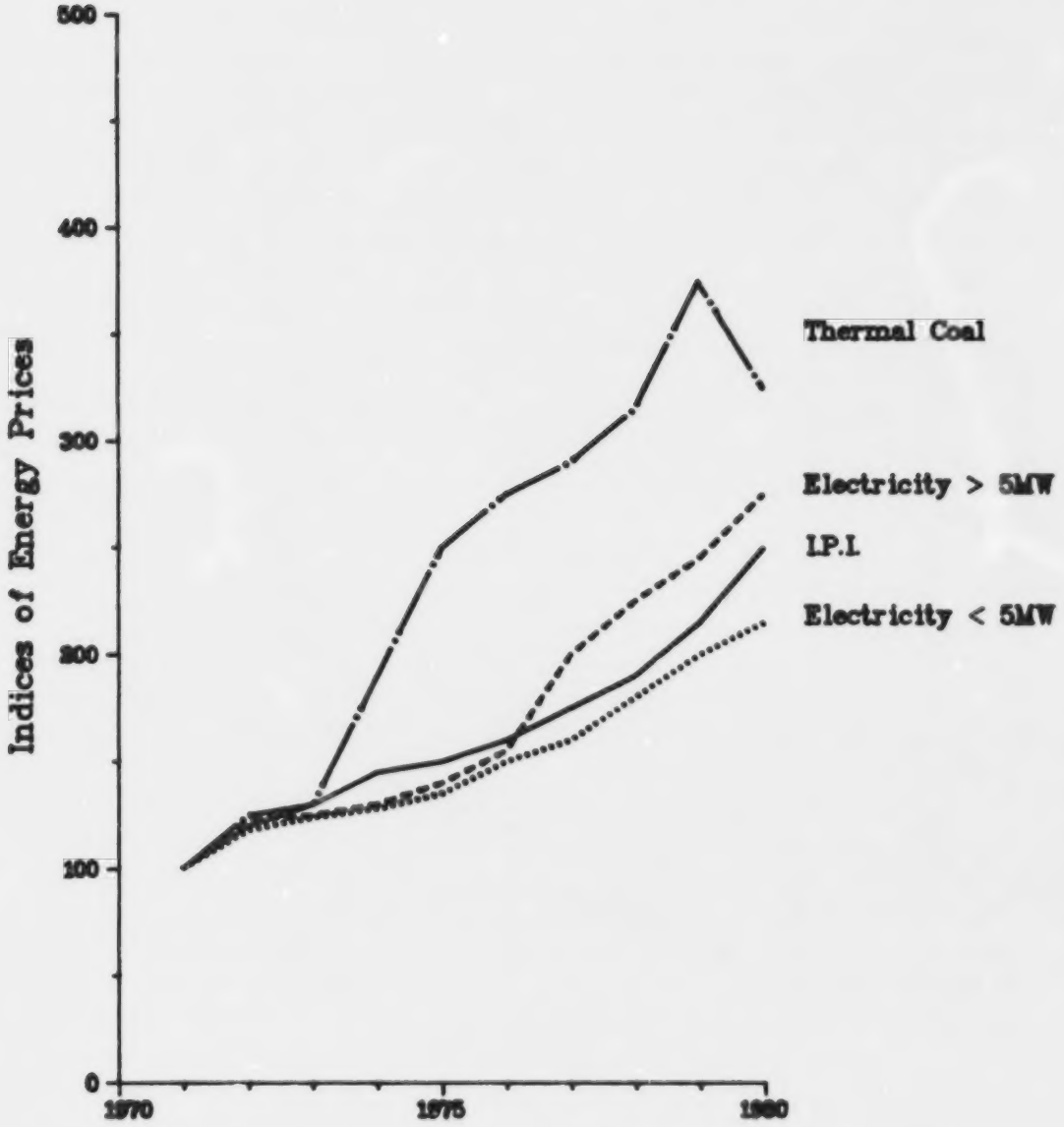
While price indices do not give an indication of the actual difference between fuel costs on a heat content basis, the movements shown here suggest two things. First, they provide some explanation of the decline in the E/GDP ratio



Note: CPI = Consumer Price Index.

Source: Statistics Canada, Catalog No. 62-010, Consumer Prices and Price Indices.

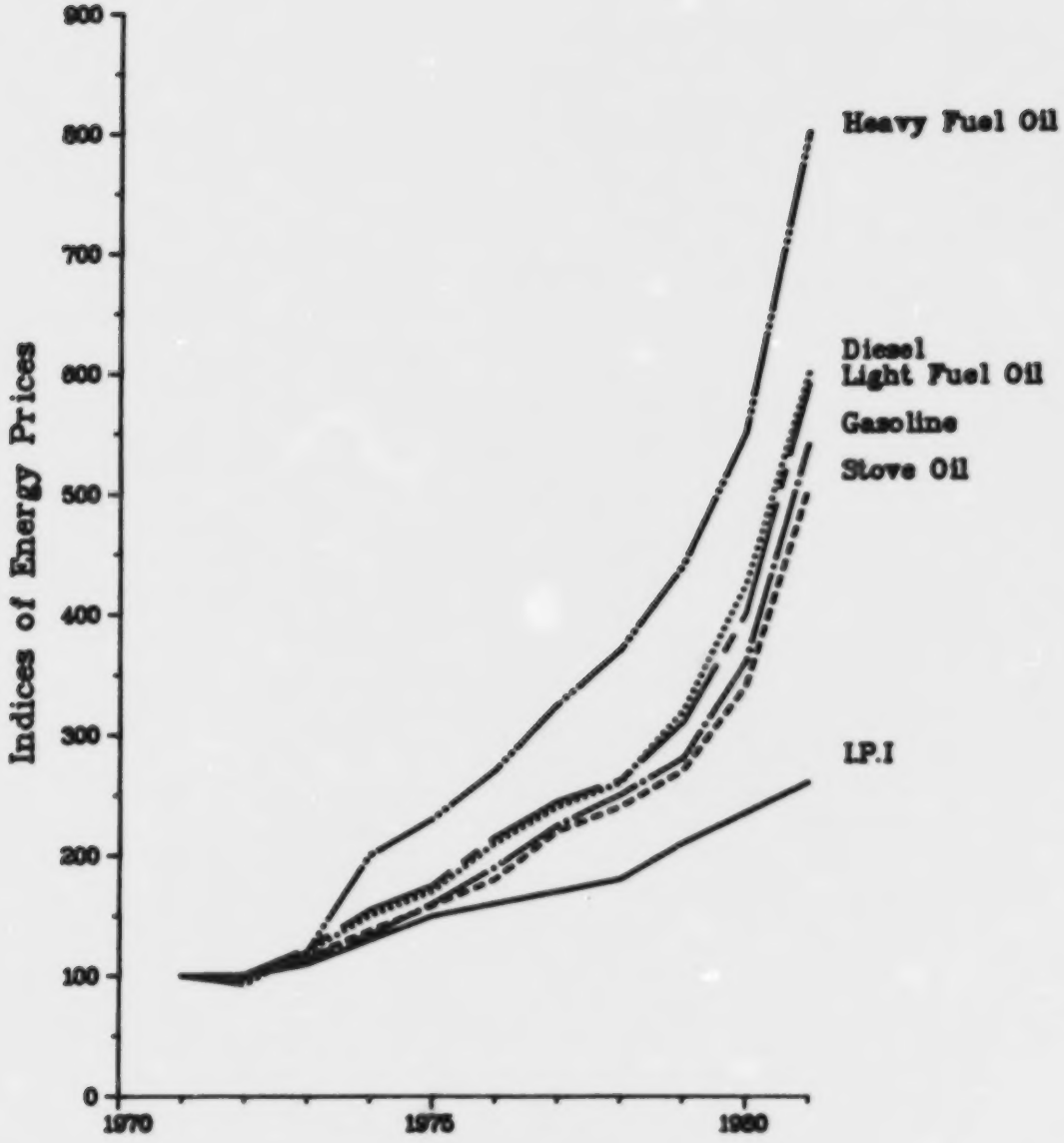
Figure 3.2: Indices of Canadian Consumer Energy Prices, 1971 – 1981



Note: I.P.I. = Manufacturing Industry Selling Price Index.

Source: Statistics Canada, Catalog No. 62-011, Industry Price Indices.

Figure 3.3: Indices of Canadian Industrial Energy Prices, 1971 – 1981



Note: I.P.I. = Manufacturing Industry Selling Price Index.

Source: Statistics Canada, Catalog No. 62-011, Industry Price Indices.

Figure 3.4: Indices of Canadian Industrial Refined Petroleum Product Prices, 1971 - 1981

shown in Figure 3.1; and second, they suggest that further inter-fuel substitution should occur because relative energy prices are changing. This is likely to occur because the prices of all fuels, with the exception of electricity (less than 5 MW of demand) in the industrial market, have increased at a rate higher than the IPI. It would be expected that, in time, those energy forms which have increased in price the least would displace other forms.

Substitution between fuels cannot, in most cases, occur in the short run, with the exception of some amounts of capital being replaced each year, permitting small desired adjustments. It may take a period of years before it is economical to introduce new capital equipment (for example, the useful life of a diesel-electric railway locomotive is about thirty years).

This section has provided a review of trends in energy prices in Canada over the past ten years. Significant changes have occurred but more are probably to come. The energy pricing agreement reached by the federal government and the Government of Alberta (July 1973) provide for increases in oil and natural gas prices contingent upon higher world prices. Electricity prices, however, are regulated at the provincial level by the various public utility regulatory boards rather than at the federal level. Thus, it is not likely that all energy prices will move evenly over the next several years, just as they have not moved in harmony in the past. This implies that energy consumers will make further adjustments in both the quantities and types of fuels consumed. Chapter 4 provides a detailed discussion of trends expected in Canadian energy prices.

3.3 Past Trends in Energy Consumption

Over the past decades market shares of the various energy forms used in Canada have changed markedly. Earlier in this century wood and coal were the major energy sources. In the postwar period and during the 1970s, these sources were very much diminished in importance with electricity generation and production of steel being the only significant uses of coal at present. Wood is presently no longer an important energy source.

If the quantities of the various energy sources used in Canada are expressed in a common unit of measurement such as joules of heat energy, a picture of total energy consumption can be produced. Figure 3.5 shows the trend in total Canadian energy consumption from 1970 to 1980 and the four major components which make up this total.[4] The four major sources of energy in order of ascending market share are coal, electricity, natural gas, and refined petroleum products. These shares were measured in the final consuming sectors and are, therefore, the sum of primary and secondary energy net of losses.

The peak in energy consumption occurred in 1980 at 7137 petajoules. By 1981, this had fallen to 6867 petajoules. The relative shares were changed with coal supplying 3.4 percent, electricity 18.9 percent, natural gas 23.9 percent and petroleum products 53.9 percent. Table 3.1 shows the total amounts of energy used over the period and the market shares held by each of the four energy types in each year.

Clear trends have emerged in the changes in market shares. The share of both coal and petroleum products declined while that of electricity increased. The share of natural gas increased each year until 1977 when it abruptly fell off.

3.4 Regional and Sectoral Trends

Regional and sectoral trends in energy consumption are not necessarily coincident with national trends. In fact, trends on a regional basis are sometimes in the opposite direction. Changes in economic activity levels in regions such as the West, for example, may result in an increasing share of energy consumption there while the trend is downwards in other parts of the country. By analyzing the energy use data on a regional and sectoral level, more detailed information about inter-fuel substitutution possibilities can be obtained. The potential for interfuel substitution away from oil may vary considerably between sectors and regions. It is therefore important to identify those sectors and regions where this potential is the greatest.

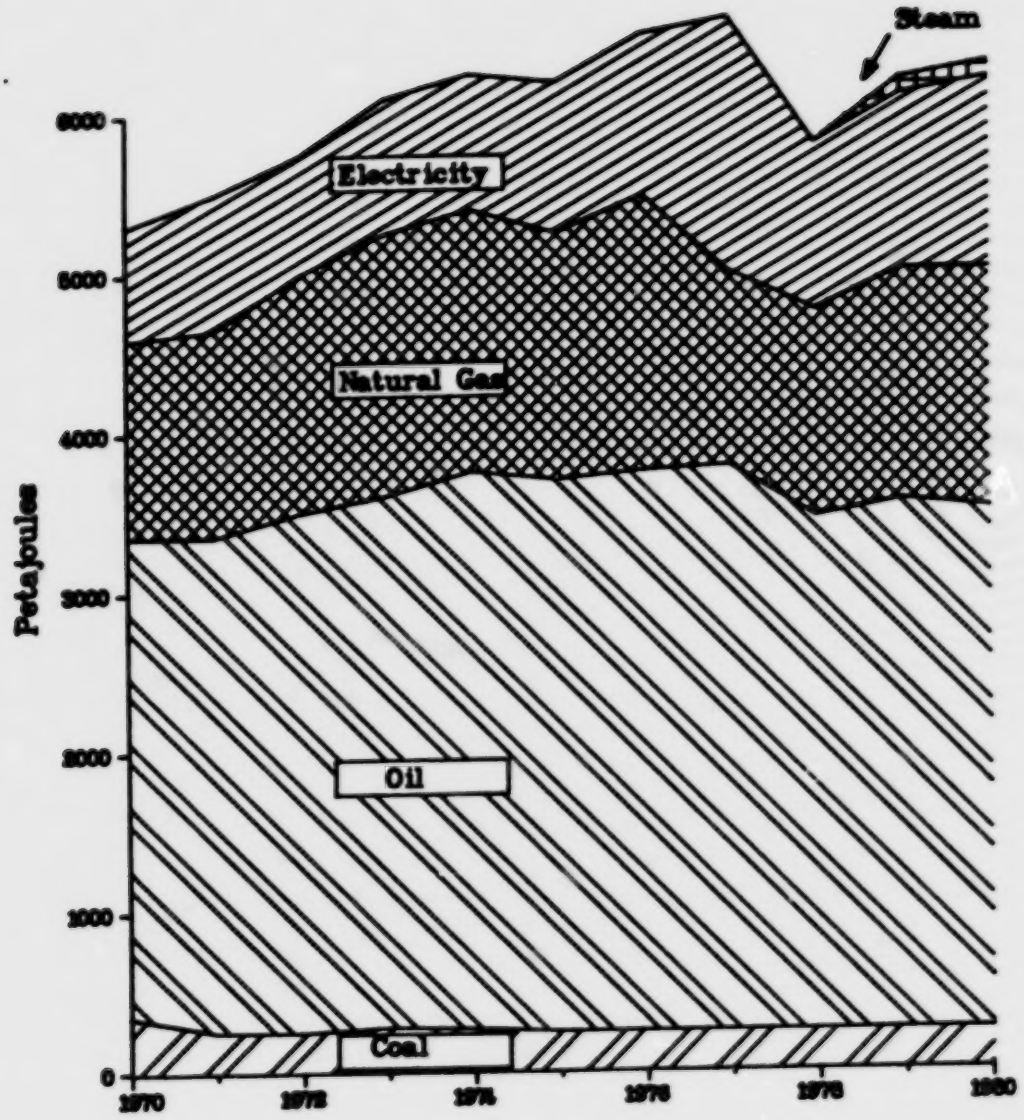
TABLE 3.1

CANADIAN ENERGY CONSUMPTION

Year	Percent Of Total Supplied By				Total Energy (Petajoules)
	Coal	Electricity	Natural Gas	Oil Products	
1970	6.4	13.7	23.8	56.0	5 330
1971	4.9	14.0	24.8	56.0	5 483
1972	4.5	14.3	25.7	55.5	5 823
1973	4.7	14.7	25.4	55.0	6 097
1974	4.4	15.3	25.3	55.0	6 304
1975	3.9	15.4	25.8	54.8	6 210
1976	4.0	16.5	27.4	55.9	6 475
1977	3.7	16.4	27.1	52.9	6 644
1978	3.6	16.8	23.1	56.5	6 798
1979	3.6	17.0	23.0	56.4	7 091
1980	3.5	17.7	23.8	54.9	7 137
1981	3.4	18.9	23.9	53.9	6 867

SOURCES: Statistics Canada: Detailed Energy Supply and Demand in Canada 57-207; and S. C. Quarterly Report on Energy Supply, Demand in Canada 57-003.

NOTE: Figures are for net domestic consumption which includes both energy and non-energy uses. Electricity is valued at 3.6 megajoules per kilowatt hour.



Source: Statistics Canada Catalog No. 57-207 and 57-003.

Figure 3.5: Total Canadian Energy Consumption In End-Use Sectors

The following sections review the consumption trends and highlight the differences over the 1970-1980 period. This was a period of changing real and relative energy prices as has been shown in Figures 3.2, 3.3 and 3.4; and thus it would be expected that the relative shares have also changed.

3.4.1 Transportation Sector

The transportation sector used 31 percent (1962 petajoules) of all energy used in Canada in 1980 and 46 percent of all refined petroleum products. This sector, in every region of Canada, is overwhelmingly dependent on refined petroleum products. These products accounted for over 95 percent of transportation energy use in 1980. The remaining 5 percent was accounted for mostly by natural gas (78 petajoules) and electricity (6 petajoules) used in pipeline pumping and compression. Use of electricity in road transportation, while long-employed by some municipal public transit systems, was still comparatively minor by 1980. Only 1.9 petajoules were used for this purpose in that year. Use of natural gas liquids (e.g., propane, butane) was also comparatively minor (1.8 petajoules).

Consumption of petroleum products and liquefied petroleum gases (LPG) increased significantly in every region of the country during the 1970s in spite of rising real prices. In the Atlantic region, consumption increased 32 percent between 1970 and 1980. In Quebec, the increase was 33 percent, while Ontario recorded a 46 percent increase. On the Prairies and in British Columbia (including the Territories) increases were 87 percent and 88 percent, respectively. The high levels of increase in the Western provinces reflect the shift of economic activity and population to these areas. (Figures A.1, A.2 and A.3 in Appendix A show the regional trends in this sector over the period 1970-1980.)

The year 1980 required the highest level of consumption of petroleum products in transportation uses in all regions with the exceptions of Ontario and the Atlantic region, where consumption peaked in 1979. A downturn in demand was experienced across Canada in 1981 for all transportation fuels. It is interesting to note that 1981 was a year of sharp increases in real energy prices (see

Figure 3.2). Sales of diesel fuel were down by 1.3 percent, motor gasoline by 12.8 percent and aviation fuel by 1.8 percent.

Coal products were still in use in the transportation sector, mainly for marine and railway locomotion in the first half of the decade, but Statistics Canada reported no usage of coal for these purposes by 1978. Because coal is difficult to utilize in transportation in comparison to the liquid and gaseous fuels, it is doubtful that it will be utilized in its natural form to any significant degree in this sector again.

The year 1982 marked a strong downturn in petroleum consumption. Consumption of motor gasoline fell by 7.8 percent in 1982 over the previous year's level, while aviation turbo fuel (naphtha-based) consumption fell by 16.5 percent and diesel fuel use fell by 8 percent.[5]

Because of Canada's high dependence on oil refinery products and declining domestic production of domestic crude oil, substitution efforts are being made in this sector. The alternatives such as compressed natural gas (CNG), electricity or the alcohol hybrids, while not yet significant, clearly have a role to play. Greater use of LPG (propane) is also a possibility. A major problem is that the conventional transportation infrastructure cannot utilize the alternatives without extra capital investment, which in some cases may be very large.

3.4.2 Industrial Sector

According to the Statistics Canada Quarterly Report on Energy Supply/Demand in Canada (57-003), industry consumed 32 percent of all energy used in Canada in 1980 and 16 percent of all refined petroleum products. In 1980, industry use of the following refinery products: kerosene and stove oil, diesel fuel, light fuel oil, heavy fuel oil, petroleum coke and LPG, obtaining 523 petajoules from these sources.

Natural gas supplied 32 percent (631 petajoules) of Canadian industry's energy demand in 1980, while electricity supplied 26 percent (504 petajoules).

The largest use of primary coal in Canada is typically for generation of electricity in thermal generating plants. In 1980, 652 petajoules of coal were utilized to generate secondary electricity. This accounts for over 57 percent of the total availability of coal in that year. The second largest use of coal in 1980 was for the production of coke for steel making, 219 petajoules. Total industrial use of coal, coke and coke oven gas (excluding the amount used for electricity and steam generation) was 248 petajoules, or 13 percent of total industrial energy consumption in 1980. Industrial coal consumption was more or less constant over the 1970-1980 period.

Total Canadian industrial use of petroleum products and LPG increased by 22.5 percent from 1970 to 1980. The highest level was recorded in 1977 at 560 petajoules. Regionally, industrial petroleum use levels moved unevenly.[6] The smallest increase was recorded in Ontario at 7.4 percent, the largest on the Prairies at 110 percent. Growth rates in other regions were 12.7 percent in Quebec, 24 percent in British Columbia and 56 percent in the Atlantic provinces. Consumption of petroleum products peaked in different years in different regions. The peak occurred on the Prairies in 1980, but much earlier in all other regions; for example, consumption peaked in Quebec in 1974 at 245 petajoules and subsequently declined by 25 percent by 1980.

All regions, with the exception of the Atlantic provinces where little natural gas is commercially available, recorded substantial growth in natural gas demand. The overall Canadian growth was 50 percent. The greatest regional increase was 126 percent in Quebec. Other increases were 37 percent in Ontario, 44 percent on the Prairies and 86 percent in B.C.

In each region of the country, electricity consumption over the 1970-1980 period peaked in 1980. Regionally, growth in electricity use was very strong. From 1970 to 1980, the increases were 60 percent in Atlantic Canada, 45 percent in Quebec, 32 percent in Ontario, 93 percent on the Prairies and 37 percent in B.C. The overall Canadian increase was about 44 percent, from 349 petajoules to 505 petajoules.

Statistics Canada now also monitors sales of steam (nuclear-generated). In 1980, these sales amounted to 43 petajoules, all of which were used by industry.

The data indicate that while the use of petroleum products was higher in 1980 than in 1970, a significant shift towards natural gas and electricity was under way as increases in total energy consumption were due more to a greater use of natural gas and electricity than to petroleum products. In fact, the use of heavy fuel oil increased from 270 petajoules in 1970 to 321 petajoules in 1980, while the use of light fuel oil declined from 62 petajoules to 45 petajoules. Diesel fuel use rose from 74 petajoules in 1970 to 134 petajoules in 1980. Kerosene and stove oil use fell from 14.8 petajoules to 4.3 petajoules over the decade. Figures A.4, A.5 and A.6 show the 1970-1980 trend in regional industrial energy consumption.[7]

3.4.3 Government-Commercial Sector

In 1980, this sector accounted for approximately 14.3 percent of total energy usage in Canada and only 5.5 percent of total refined petroleum product use, mainly light and heavy fuel oil. Coal products were still in use in small amounts early in the decade, but by 1975 consumption was insignificant. Natural gas and electricity accounted for 44.9 percent and 29.6 percent, respectively, of this sector's total energy consumption in 1980, while petroleum products composed 25.3 percent.

Trends in consumption of petroleum products differed greatly across regions. Consumption levels remained static in British Columbia and on the Prairies, while a moderate decline occurred in the Atlantic area. In Quebec and Ontario consumption fell dramatically by 1980: 57 percent in Ontario and 44 percent in Quebec.

In stark contrast, the use of natural gas increased in all regions where it was available. Increases over the ten-year period were 171 percent in Quebec, 60 percent in Ontario, 119 percent on the Prairies and 105 percent in B.C. Natural gas service was not available in the Atlantic region.

The use of electricity also increased greatly in all regions: 44 percent in the Atlantic, 43 percent in Quebec, 57 percent in Ontario, 83 percent on the Prairies and 138 percent in British Columbia and the Territories. Electricity, and especially natural gas made strong gains at the expense of petroleum products during this period. (Figures A.7, A.8 and A.9 in Appendix A illustrate the trends in regional energy consumption in the government-commercial sector over the 1970-1980 period.)

3.4.4 Residential-Farm Sector

In 1980, this sector used 22 percent of total Canadian energy consumed in end-use sectors and approximately 19 percent of refined petroleum product demand (including LPG). Electricity and natural gas supplied 24 percent and 31 percent respectively of total energy needs in 1980. (Figures A.10, A.11 and A.12 in Appendix A show the trends in this sector.)

The trends in the consumption of refined petroleum products across regions were strong. Significant reductions in consumption occurred in each region with the exception of the Prairie provinces where consumption rose by 71 percent between 1970 to 1980. Consumption fell by 12 percent in the Atlantic area, 20 percent in Quebec, 21 percent in Ontario, and 15 percent in B.C.

Strong growth in demand for natural gas was evident in each region west of Quebec. The increases were 27 percent in Quebec, 88 percent in Ontario, 46 percent on the Prairies and 64 percent in B.C.

Electricity use had also greatly increased over the decade: 167 percent in the Atlantic region, 149 percent in Quebec, 87 percent in Ontario, 100 percent on the Prairies and 100 percent in B.C. and the Territories.

Electricity and natural gas made clear gains in the residential farm market, while petroleum product use, mainly light fuel oil, declined in importance in all regions except the Prairies.

3.4.5 Summary Comment

This brief review has shown that trends in consumption of the various energy sources vary not only by type of fuel, but also from one region to the next. Also, the changes in relative prices have been different in the various regions of Canada, inducing different amounts of conservation and substitution. Furthermore, higher levels of economic activity on the Prairies, especially in Alberta and Saskatchewan have contributed to increased demand for almost every fuel type in those provinces.

Overall, clear trends in inter-fuel substitution are evident in three of the four sectors investigated here. Reliance on refined petroleum products and LPG, while still extensive, has declined significantly in the Industrial, Government-Commmercial and Residential-Farm sectors in most regions. These decreases have been particularly important in Quebec and Ontario, historically the largest market areas for refined petroleum products in Canada.

In contrast to this declining importance of oil-based energy, the use of electricity and natural gas has increased greatly in these three sectors in all regions, with the exception of the Atlantic provinces. Increased penetration of natural gas and electricity may be expected in the future if price differentials relative to most oil products widen further. However, this may not be imminent following recent declines in international oil prices.

In terms of size, the potential for substitution away from petroleum products in the non-transportation sectors is the greatest in Ontario and Quebec. In 1980, the non-transportation sectors in these two provinces used 61 percent of all refined petroleum products and LPG devoted to non-transportation uses in Canada. Any effort to induce large-scale off-oil substitution must, therefore, ultimately involve the non-transportation sectors of Ontario and Quebec.

As noted above, the transportation sector is the largest end user of petroleum products. The time series presented shows that this sector recorded increasing levels

of energy use in each region throughout the decade. In contrast to the other sectors, there was virtually no penetration by other energy sources. This may not be very surprising considering certain factors. Firstly, real energy prices did not begin to rise strongly in this sector until 1981. Furthermore, in the short run it is difficult to reduce fuel consumption without changing the capital stock which is not something which occurs on a large scale within a year or two. Beyond these factors, confusion regarding future prices of gasoline and diesel fuel vis-a-vis the alternatives may be contributing to vehicle owners' complacency.

The small amounts of natural gas use shown in 1979 and 1980 were devoted exclusively to pipeline fuel. In previous years this use was classified as energy supply industry consumption rather than transportation use by Statistics Canada. It should also be noted that the levels of energy use include LPG of which propane has been suggested as an alternative transportation fuel. While there is some road transport use of propane, in 1980 this amounted to just under 2 petajoules or to 0.0001 percent of total transportation energy used in Canada. The heavy dependence of this sector on petroluem products has spawned considerable research into alternative fuels which might replace gasoline, diesel and aviation turbo-fuel. While it is likely that over the long run some substitution will occur, the inherent difficulties of utilizing alternative fuels in transportation and the overwhelming dependence of this sector on petroleum products would suggest that most of its energy requirements will continue to be met by crude oil-based products well into the next century.

Footnotes

[1]James M. Griffin, Energy Conservation in the OECD, 1980 to 2000 (Cambridge, Massachusetts: Ballinger Publishing, 1979), p. 6

[2]Ibid., p. 66

[3]Energy users make decisions about energy consumption based on marginal price, that is, the actual cost to the user of consuming one more unit of energy. Unfortunately, it is usually difficult to obtain marginal price information to examine relative price differentials and their movements over time. This has necessitated reliance in many studies on average cost data.

[4]The data for this figure and those which follow in this chapter were taken from Statistics Canada, Detailed Energy Supply and Demand in Canada, Catalogue 57-207 and Quarterly Report on Energy Supply/Demand in Canada, Catalogue 57-003.

[5]Statistics Canada, Refined Petroleum Products, Bulletin 45-004.

[6]Gordon W. Douglas and Ellen F. Battle, Energy and Regional Investment in Canada, Study No. 17 (Calgary: Canadian Energy Research Institute, March 1983).

[7]These data do not distinguish between growth and growth due to inter-fuel substitution.

Chapter 4

CONVENTIONAL ENERGY SOURCES IN CANADA

In Chapters 1 and 2 a review of the economic theory underlying the substitution of one fuel for another was provided and, in general, the substitution of other inputs for energy in production and in consumption. Chapter 3 presented a review of Canadian energy consumption trends over the decade of the 1970s. In this chapter the results of econometric simulations which were undertaken in an attempt to assess the extent to which inter-fuel substitution will occur in Canada, based upon certain assumptions about the movement of energy prices, are discussed.

4.1 The Mace Model

Simulations were undertaken using the Mace model--an econometric model of the Canadian economy.[1] Development of this model was begun in about 1972 at The University of British Columbia by Dr. John Helliwell and Dr. Robert McRae (now at The University of Calgary). This model is also being used by the Economic Council of Canada.

Mace is essentially a two-part model composed of a macroeconomic and an energy demand and supply sub-model. There are eleven sectors in total, containing 800 endogenous variables, 300 exogenous variables and 540 coefficients. The macro block contains five sectors: supply and factor demands, personal and foreign expenditures on goods and services, prices, wages and national income sector, a balance of payments and capital movements sector, and a government and private finance sector. The energy block contains the energy demand sector, a non-frontier natural gas supply sector, a non-frontier crude oil supply sector, oilsands production, a frontier pipeline and Mackenzie Delta gas production sector, and a fuel losses sector.

The macro block produces everything other than energy by using labour, capital and energy. The supply sector uses

a production function to determine gross output. Domestic consumption and exports, excluding energy, are modeled in the absorption sector. A price-wage block is used to explain determination of output prices, absorption prices, earnings, non-energy export prices and the national income identities.

The international finance sector determines exchange rate and balance of trade values. A domestic finance sector allows for the determination of the demand for money, business assets, taxes and government transfer payments.

The energy block uses capital and a resource base to produce and distribute energy. The energy demand sector of Mace is a regional, pooled data model where energy demand (measured in output British thermal units) is aggregated across the residential, commercial, industrial and transportation sectors in each of the five regions in Canada--Atlantic Canada, Quebec, Ontario, the Prairie provinces, and British Columbia. For each of these regions the demand for crude oil, natural gas, electricity and coal is determined. Mace also contains a thermal electricity sub-section which determines the amount of secondary electricity (non-hydro or nuclear-generated) required and the quantities of primary fuels (oil, gas or coal) required to generate it in each region.

The approach taken to estimating energy demand is called the total energy (or 'top down') approach. The model first regresses total energy demand for each region on the region's share of real domestic product, a ratio of the region's weighted average of energy prices to the average of energy prices in Canada and total Canadian energy demand. The estimation procedure is 'iterative Zellner' and the estimation period is 1961-1980. Once the total quantity of energy demanded is determined for the region, each fuel's quantity share can be estimated. Each share is regressed on the user prices of oil, gas, electricity and the number of gas pipeline distribution kilometers. The quantity of hydro and nuclear generated electricity supplied is exogenously set to grow at 2 to 6 percent per year depending upon the region, and desired secondary electricity is the residual, using the endogenous electricity demand determined in the above manner. The primary energy fuels used to generate the electricity are

determined in a procedure similar to that described above. The growth in gas pipeline kilometers is similarly set exogenously. The rate of growth in coal demand outside the secondary electricity model is set exogenously at 4 percent per year.[2]

In the Mace model the prices of electricity and coal are both determined by annual escalation equal to the rate of inflation. Thus, there is no significant movement in real electricity or thermal coal prices over the simulation period, 1983 to 1990.[3] The model version used for these simulations was the latest available (August 1982) which had the modifications to the National Energy Program (NEP) and the September 1981 federal-provincial energy pricing agreements built into it.

The NEP and federal-provincial agreements represent a complex system of pricing arrangements for crude oil and natural gas. Figures 4.1 to 4.3 show generally how these pricing arrangements are handled in the Mace model.

The procedure begins with the conversion of imported f.o.b. prices ($U.S.) to landed prices (CIF) in Canadian dollars at Montreal. The macro block generates forecasts of the price of foreign exchange to do this. The price of this oil forms a ceiling above which, under the agreements, the domestic price of new oil cannot go. Domestically produced oil is divided into two types under the July 1983 agreement. New oil, discovered after December 31, 1973, receives the New Oil Reference Price (NORP) which rises according to a negotiated schedule. Old oil, discovered before 1974, receives the Conventional Old Oil Price (COOP), which is also rising according to the negotiated agreement. A volume-weighted average price, called the blended price, is determined from these three prices and their respective quantities (including imports). Because a large percentage of domestically produced oil qualifies for only COOP, the blended price is lower than the landed cost of imported oil.

There are maximum ceilings which will restrict the level of these prices. NORP cannot rise above a three-month weighted average of imported oil, adjusted for quality. Scheduled increases for COOP oil cannot take the price above

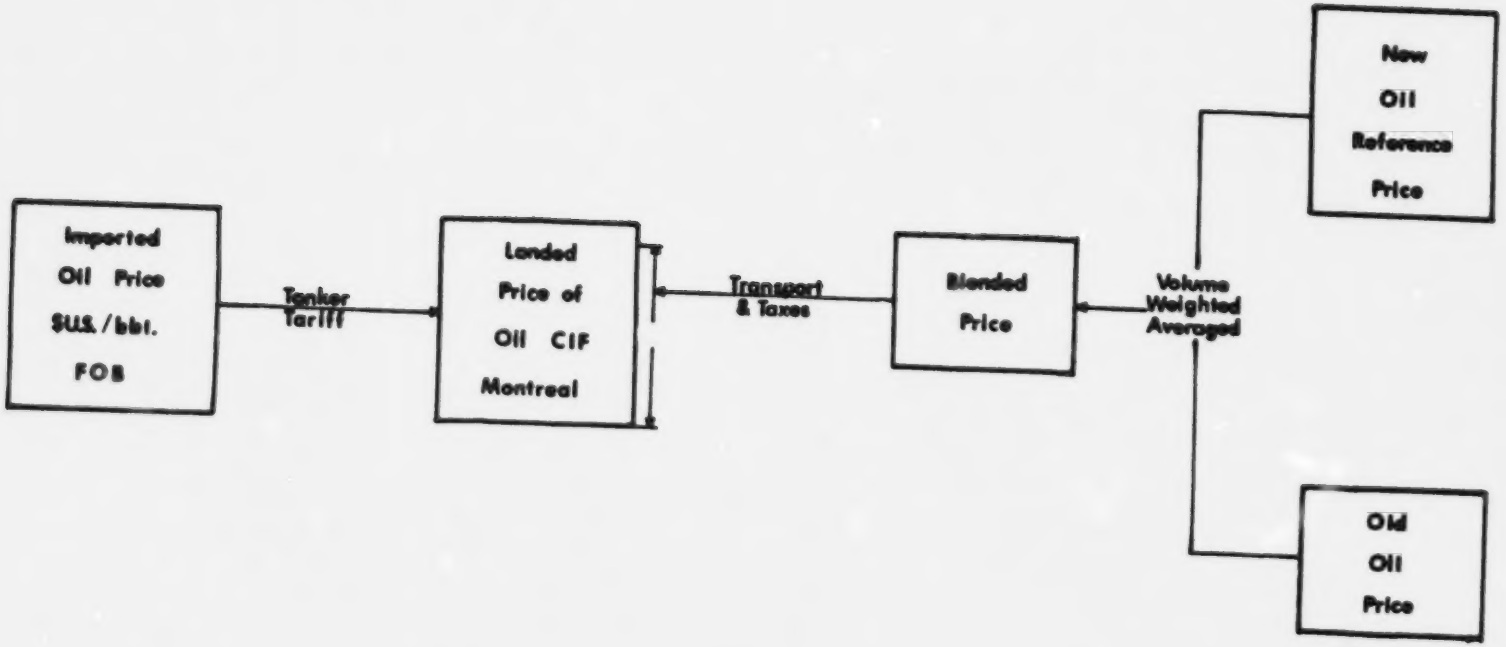


FIGURE 4.1: CANADIAN OIL PRICE REGULATION

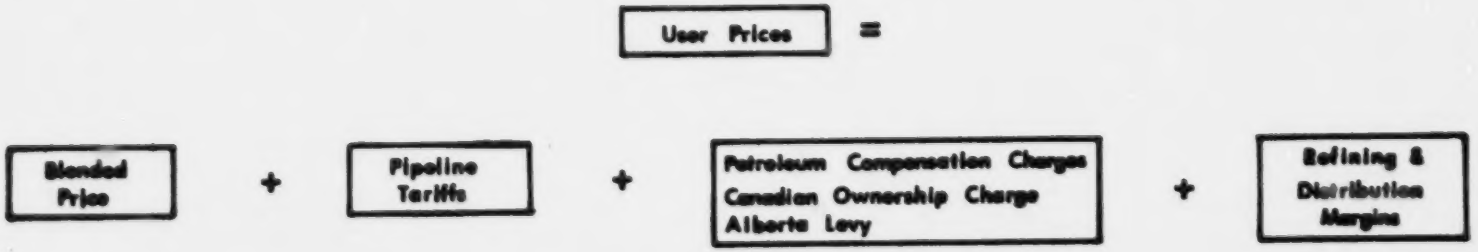


FIGURE 4.2: DOMESTIC USER OIL PRICES

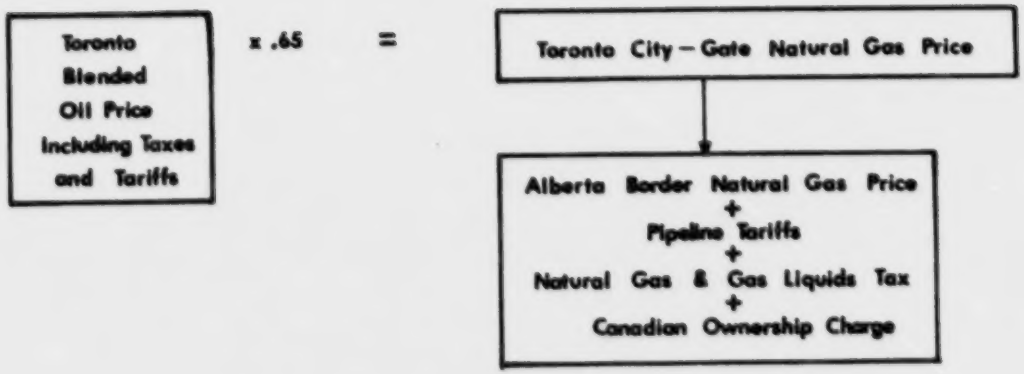


FIGURE 4.3: EASTERN NATURAL GAS PRICES

75 percent of the landed price of oil adjusted for quality. However, there is no mechanism to rollback domestic prices when international prices fall. User prices for oil are determined by adding pipeline tariffs, refinery taxes such as the Petroleum Compensation Charge and the Canadian Ownership Special Charge, and refining and distribution margins to the blended price.

The price of natural gas used east of Alberta is determined by the 65 percent rule. The Toronto city gate price is set to be 65 percent of the blended price of oil including pipeline tariffs and taxes at Toronto on the basis of energy content equivalency. The Alberta border price of natural gas is scheduled to rise 25¢ per thousand cubic feet (Mcf) every six months independent of other developments. Pipeline tariffs and the Natural Gas and Gas Liquids Tax (NGGLT) plus the Alberta border price must equal the 65 percent measure in Toronto. Stagnant oil prices and a rising Alberta border price suggest a declining NGGLT.

This brief outline reflects the pricing mechanisms resident in the Mace model which, with appropriate assumptions, generate the quantities of fuel demanded. Comparison of fuel quantities demanded under different pricing scenarios are used later in this paper to provide the basis for analysis of the potential for inter-fuel substitution. The pricing scenarios presented are based on the assumption that the energy pricing agreements, including the 75 percent cap on old oil prices, stay intact.

4.2 International Pricing Developments

The years 1981 and 1982 were marked by considerable instability in the world economy and this was reflected in the international and domestic energy markets. Continued recession and conservation in the Organization for Economic Co-operation and Development (OECD) countries contributed to real declines in the price of internationally traded oil. In February 1983, Nigeria officially dropped the posted price of its marker crude by $5.50 (U.S.) per barrel.[4] A general consensus is that real oil prices will not recover until the late 1980s. This, of course, would have important ramifications for the domestic pricing schedules of old oil and the

new oil reference price. The price forecast for imported oil, upon which the extent to which domestic prices could rise is based on the energy agreements, is now far above what the actual prices are likely to be over the remainder of the decade. In fact, at time of writing (May 1983) the domestic price for old oil was 84 percent of the cost of landed oil of equivalent quality at Montreal. If international oil prices remain stagnant, no further domestic increases will take place.

These developments are likely to have a significant effect on the extent to which inter-fuel substitution occurs in Canada and also on the goal of attaining oil self-sufficiency. Intuitively, one would expect that a slowdown in the rate of increase of oil prices would inhibit energy and especially oil conservation efforts. There have been suggestions that the 75 percent restriction on old oil prices should be removed and all domestic oil priced at the international level. Because 80 percent of domestic oil production was 'old' oil in 1982 (discovered before January 1, 1974), allowing increases above the 75 percent level would raise prices to consumers as well as revenues to the industry and governments. This would have the effect of encouraging more oil conservation, inter-fuel substitution, and of increasing oil exploration and development.

The results of the Mace simulations presented in this chapter are based upon a continuance of the 75 percent cap on old oil and existing policies. However, there is a reasonable chance that, because of moderating international prices, stagnating government oil revenues, and the need to stimulate exploration, this cap will eventually be dropped. Therefore, simulations were also performed with the 75 percent cap removed; these are reported in the next chapter.

The uncertainty which surrounds international oil prices and domestic oil prices necessitates that more than one oil price scenario be used to predict future levels of consumption and thus inter-fuel substitution of the four primary fuels. Four international oil price scenarios were selected with one being considered as the 'most likely'. Four simulation runs with the Mace model were then generated using these scenarios. Three simulations were generated with

the price of old oil rising to the new oil reference price. These three simulations indicate what would happen if the federal/provincial agreements were renegotiated to remove the price cap on old oil.

4.3 Price Scenarios

Tables 4.1a and 4.1b show the four pricing scenarios used in the analysis. They are given in American dollars per barrel f.o.b. Montreal. The high scenario (Number 1) has prices remaining constant in nominal terms until 1985. In 1986 prices escalate by $2/bbl (U.S.) and thereafter increase at approximately 7 percent per year. The most likely scenario (Number 2) sees prices falling to $30/bbl (U.S.), nominal, in 1983 and remaining constant through 1985. In 1986, and in each subsequent year, they rise at 10 percent per year.

A third scenario, which is perhaps somewhat less likely to occur, postulates that prices will fall to $25/bbl (U.S.) in 1983, remain at that level for 1984, then rise at approximately 8 percent per year to 1990. A fourth scenario suggests that oil prices will fall to $20/bbl (U.S.) and remain there for the remainder of the decade. This is perhaps the least likely outcome of current international oil market events. It should be noted that, in all of the simulation results which follow, the regulated price of natural gas remains at 65 percent of commodity equivalent with oil even though this implies, with low oil price increases, the unlikely imposition of a negative Natural Gas and Gas Liquids Tax. The tacit assumption is that if the Natural Gas and Gas Liquids Tax drops to zero, then the 50¢ per year Alberta border price increases will be ultimately rolled back. Under the terms of the latest agreement, the federal government has guaranteed that natural gas prices will not exceed 65 percent of the price of oil.

4.4 Gross National Product Growth

The level of GNP is a very important variable in the determination of energy demand. It is generally expected that increases in the level of GNP will result in increased energy demand. Real GNP declined in Canada by 4.8 percent in 1982 from the previous year's level. However, positive

TABLE 4.1a

IMPORTED OIL PRICE SCENARIOS
($U.S./$m^3$ f.o.b. Montreal)

	Scenarios			
Year	1	2	3	4
1983	213.62	188.49	157.07	125.66
1984	213.62	188.49	157.07	125.66
1985	213.62	188.49	169.64	125.66
1986	226.19	207.34	182.20	125.66
1987	242.40	228.07	197.85	125.66
1988	259.40	250.88	213.62	125.66
1989	277.52	275.95	230.77	125.66
1990	299.70	303.60	249.25	125.66

TABLE 4.1b

IMPORTED OIL PRICE SCENARIOS
($U.S./bbl f.o.b. Montreal)

	Scenarios			
Year	1	2	3	4
1983	34.00	30.00	25.00	20.00
1984	34.00	30.00	25.00	20.00
1985	34.00	30.00	27.00	20.00
1986	36.00	33.00	29.00	20.00
1987	38.58	36.30	31.49	20.00
1988	41.28	39.93	34.00	20.00
1989	44.17	43.92	36.73	20.00
1990	47.70	48.32	39.67	20.00

growth is expected to resume in 1983 at around 1-2 percent. The macro block part of the Mace model produces endogenous estimates of the level of GNP based upon specified macro-economic assumptions.

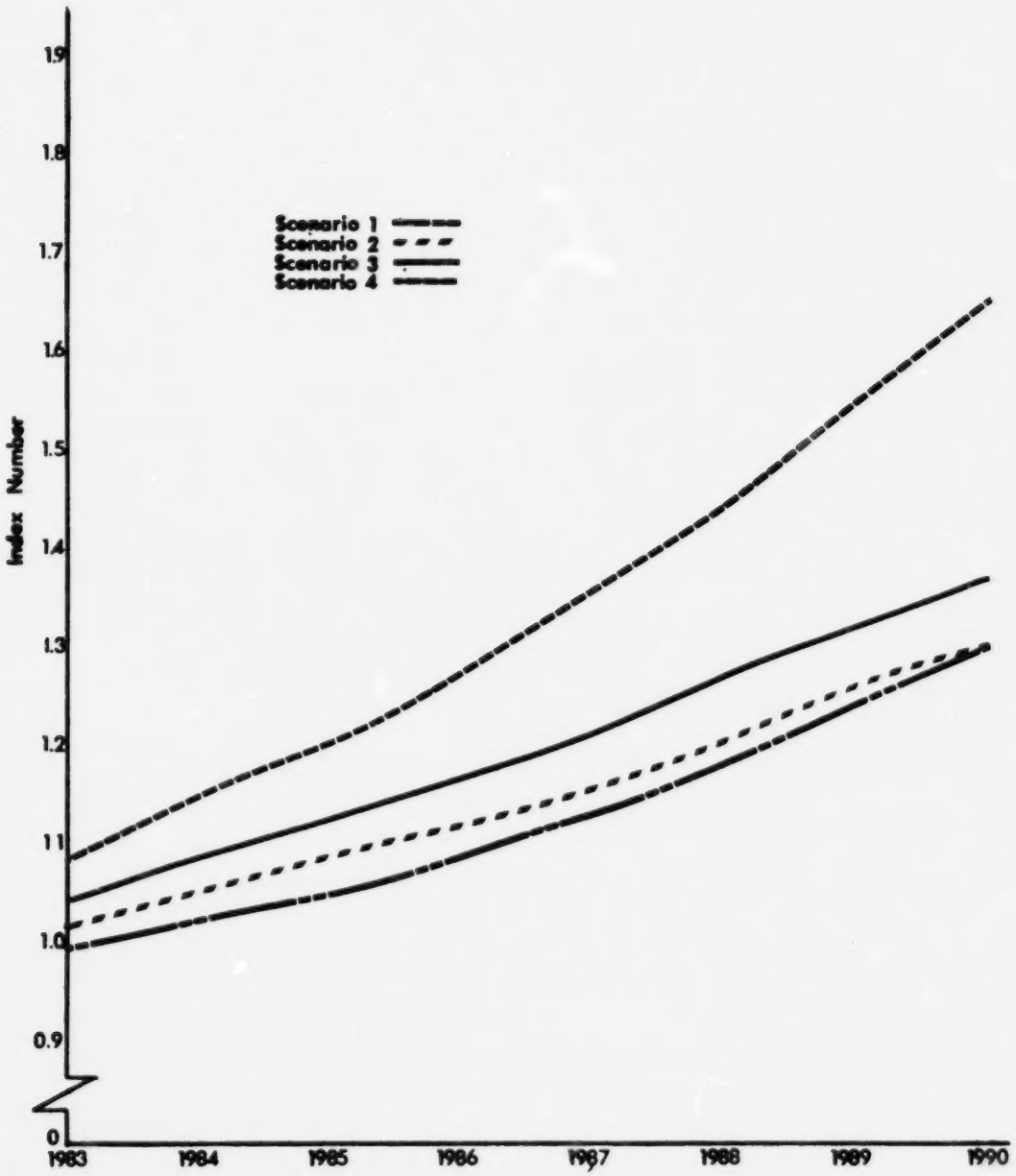
4.5 Energy Demand in Canada

Projections of oil prices in the 1980s contained in the original federal-provincial agreements of 1981 are now recognized as being overly high. Reduced price increases will mean that the stimulus for oil conservation will not be as strong as it would otherwise be. Similarly, the stimulus to substitute other energy forms for oil will not be as strong. With slower growth in oil and gas prices, relatively more oil and gas will be used and relatively less electricity and coal. Oil price scenario Number 1 (the highest price scenario) generates the lowest growth in total Canadian energy demand. Figure 4.4 shows the relative growth curves for total final energy demand resulting from the four simulations for the period 1983 to 1990. Scenario Number 1 results in an increase in consumption of 371 output petajoules annually by 1986 and an increase of 1241 petajoules annually over 1983 levels by 1990. Scenario Number 2, with oil prices reduced to significantly lower levels during 1983 to 1986, ends with a higher price in 1990. Thus, while annual consumption is higher under this scenario in the middle of the decade, it is lower in 1990.

Scenario Number 3, which has even lower oil prices, leads to a considerable increase in annual energy consumption for each year to 1990. Consumption rises by almost 206 petajoules over Scenario Number 1 in 1983 and by almost 296 petajoules by 1990.

Scenario Number 4 reduces oil prices to very low and declining real levels for the remainder of the decade. This results in a considerable increase in annual consumption, such that by 1990, annual consumption is up by 2213 petajoules above 1983 levels.

A statistic of interest is the ratio of output Btu's to real GNP. This ratio which can be considered a measure of energy intensity. This value is given in billions of output



Note: Index numbers are annual quantities divided by the 1983 value for Scenario 1. I.e. x/x =1

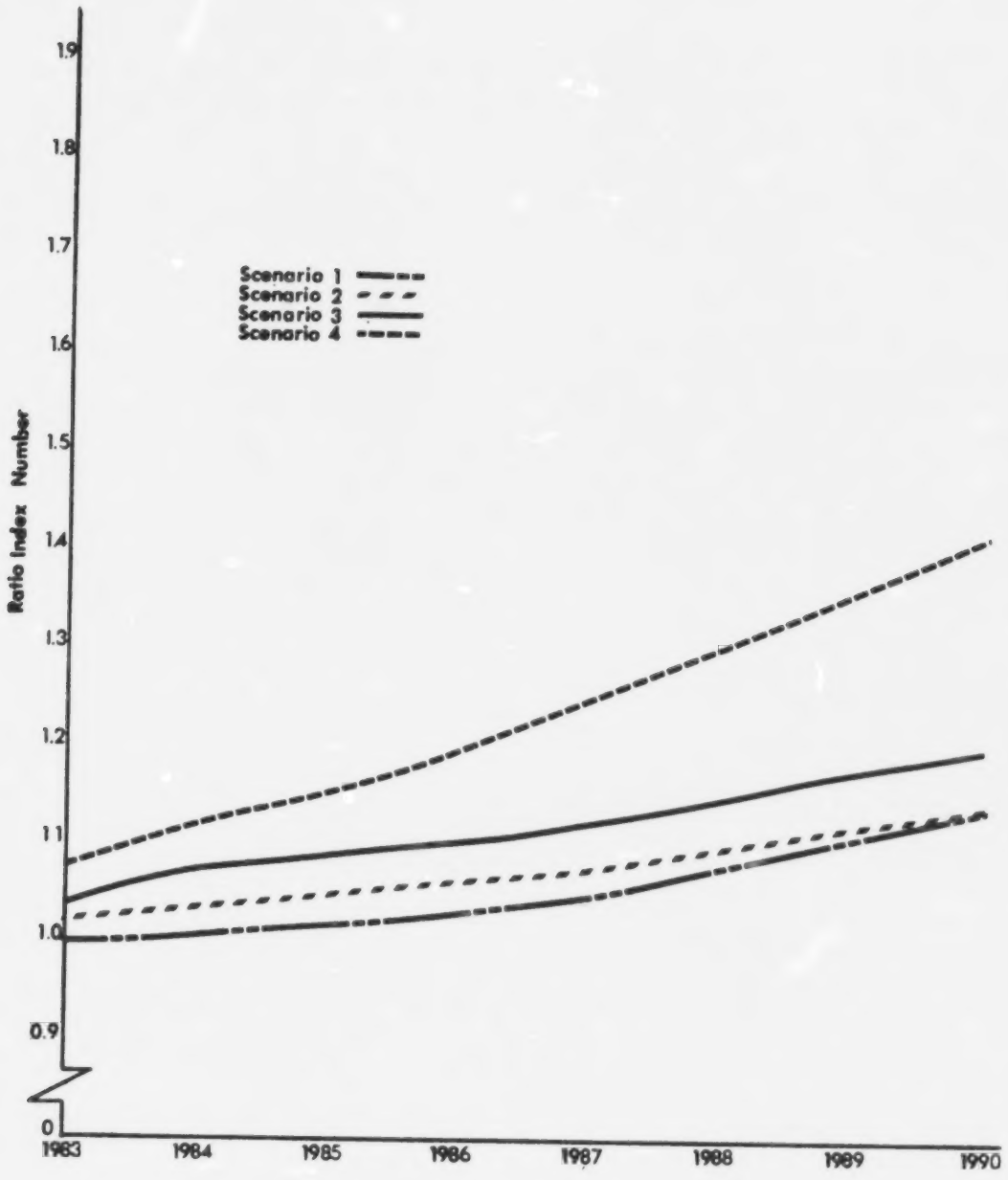
FIGURE 4.4: GROWTH IN QUANTITY OF FINAL ENERGY CONSUMED IN CANADA

Btu's demanded for every 1971 dollar of real Gross National Product. A comparison of this measure generated by the four oil price scenarios is shown in Figure 4.5. The output Btu/GNP ratio rises in all four scenarios with the highest oil price scenario generating the slowest growth in energy intensity. Scenario Number 1 generates a 14 percent increase in the ratio from 1983 to 1990, while Scenario Number 4 generates a 31 percent increase in the ratio. (The reader should note that the methodology of determining the Btu/GNP figures differs from that used to calculate the E/GNP ratio described in Chapter 3. The two measures are not the same.)[5]

Movements in the Btu/GNP ratio can be used to indicate the extent to which the economy is conserving energy. A reduction in ratio means that less energy is being used in total relative to the level of real GNP. This does not prevent consumption of one or more energy commodities from actually increasing. The reader should also remember that interpretation of movements in this ratio are subject to the qualifications given in Chapter 2 concerning the E/GDP ratio.

4.6 Inter-Fuel Substitution

Simulations done using the Mace model have provided estimates of inter-fuel substitution. Of particular interest is the extent to which the relative market shares for each fuel change in response to the changing prices. Based on the total quantity of energy demanded shown in Table 4.2, the total Canadian market for energy is broken down into shares for crude oil, natural gas, coal and electricity. Tables 4.3 to 4.6 show the estimated quantities in natural units. These quantities are also shown in petajoules in Tables 4.7 to 4.10. The reader should note that the amounts of electricity shown include both primary (nuclear and hydro-generated) and secondary (oil, gas or coal-generated) electricity. Adding together the amounts of energy given in Tables 4.3 to 4.6 will therefore overstate final demand by the amounts of oil, gas and coal which were used to generate secondary electricity.



Note: Index numbers are annual quantities divided by the 1983 value for Scenario 1.

FIGURE 4.5: CANADIAN OUTPUT BTU/GNP.

TABLE 4.2

TOTAL FINAL ENERGY DEMAND IN CANADA
(petajoules)

Year	Scenarios			
	1	2	3	4
1983	4083.9	4167.3	4289.6	4439.4
1984	4194.7	4308.6	4481.6	4693.7
1985	4322.3	4466.9	4622.0	4936.4
1986	4455.3	4595.6	4781.3	5217.0
1987	4631.5	4758.1	4973.3	5557.7
1988	4853.0	4948.0	5189.6	5935.4
1989	5100.9	5146.3	5414.3	6630.0
1990	5324.6	5319.3	5621.0	6752.0

TABLE 4.3

QUANTITY OF OIL DEMANDED IN CANADA
($10^6 m^3$)

Year	Scenarios			
	1	2	3	4
1983	83.4	85.4	88.3	91.8
1984	84.5	87.0	90.9	95.8
1985	85.7	88.8	92.2	99.2
1986	86.8	89.8	93.8	103.3
1987	88.8	91.4	96.0	108.5
1988	91.4	93.3	98.4	114.1
1989	94.3	95.2	100.7	119.6
1990	97.4	97.2	103.4	113.5

TABLE 4.4

QUANTITY OF NATURAL GAS DEMANDED IN CANADA
($10^9 m^3$)

	Scenarios			
Year	1	2	3	4
1983	51.9	53.9	56.9	61.0
1984	54.6	57.0	61.0	66.3
1985	57.9	60.9	64.1	71.9
1986	60.4	63.2	67.2	78.0
1987	63.7	66.2	70.9	85.8
1988	68.0	68.5	75.4	95.6
1989	73.0	74.0	80.3	106.7
1990	77.6	77.5	84.6	117.2

TABLE 4.5

QUANTITY OF ELECTRICITY DEMANDED IN CANADA
(10^9 kW.h)

	Scenarios			
Year	1	2	3	4
1983	341.9	343.0	344.6	346.4
1984	347.5	349.8	352.8	355.7
1985	354.4	358.1	362.4	367.3
1986	364.5	369.1	374.4	381.9
1987	378.2	382.8	388.8	398.9
1988	393.6	397.3	403.1	415.3
1989	410.1	411.9	417.7	431.3
1990	425.5	425.4	431.6	447.5

TABLE 4.6

QUANTITY OF COAL DEMANDED IN CANADA
(millions of tonnes)

	Scenarios			
Year	1	2	3	4
1983	25.8	25.4	24.9	24.2
1984	26.4	26.2	25.9	25.2
1985	27.3	27.2	26.9	26.4
1986	28.6	28.5	28.1	27.9
1987	29.9	30.0	29.4	29.2
1988	31.4	31.0	30.5	30.6
1989	32.8	32.2	31.8	31.8
1990	34.2	33.5	33.0	33.1

TABLE 4.7

TOTAL DEMAND FOR OIL IN CANADA
(petajoules)

	Scenarios			
Year	1	2	3	4
1983	1519.2	1556.1	1612.0	1682.7
1984	1538.2	1585.7	1659.6	1753.4
1985	1560.3	1620.5	1683.8	1817.8
1986	1581.5	1637.4	1712.3	1894.8
1987	1618.4	1667.0	1753.4	1995.0
1988	1667.0	1702.8	1798.8	2101.6
1989	1720.7	1737.6	1842.0	2209.2
1990	1777.7	1774.5	1891.6	2316.3

TABLE 4.8

TOTAL DEMAND FOR NATURAL GAS IN CANADA
(petajoules)

	Scenarios			
Year	1	2	3	4
1983	1430.6	1490.0	1582.5	1707.0
1984	1508.7	1582.5	1702.8	1863.1
1985	1592.0	1683.8	1781.9	2017.2
1986	1668.0	1752.4	1871.6	2199.7
1987	1764.0	1839.9	1981.3	2436.0
1988	1894.0	1951.8	2117.4	2731.4
1989	2042.5	2072.0	2261.9	3067.9
1990	2166.0	2162.8	2380.1	3404.4

TABLE 4.9

TOTAL DEMAND FOR ELECTRICITY IN CANADA
(petajoules)

	Scenarios			
Year	1	2	3	4
1983	1231.2	1234.4	1240.7	1247.0
1984	1251.2	1259.7	1270.2	1280.8
1985	1275.5	1289.2	1304.0	1321.9
1986	1312.4	1328.3	1348.3	1374.7
1987	1361.0	1377.8	1398.9	1435.9
1988	1416.9	1429.5	1450.6	1494.9
1989	1476.0	1482.3	1503.4	1553.0
1990	1530.8	1530.8	1554.0	1611.6

TABLE 4.10

TOTAL DEMAND FOR COAL IN CANADA
(petajoules)

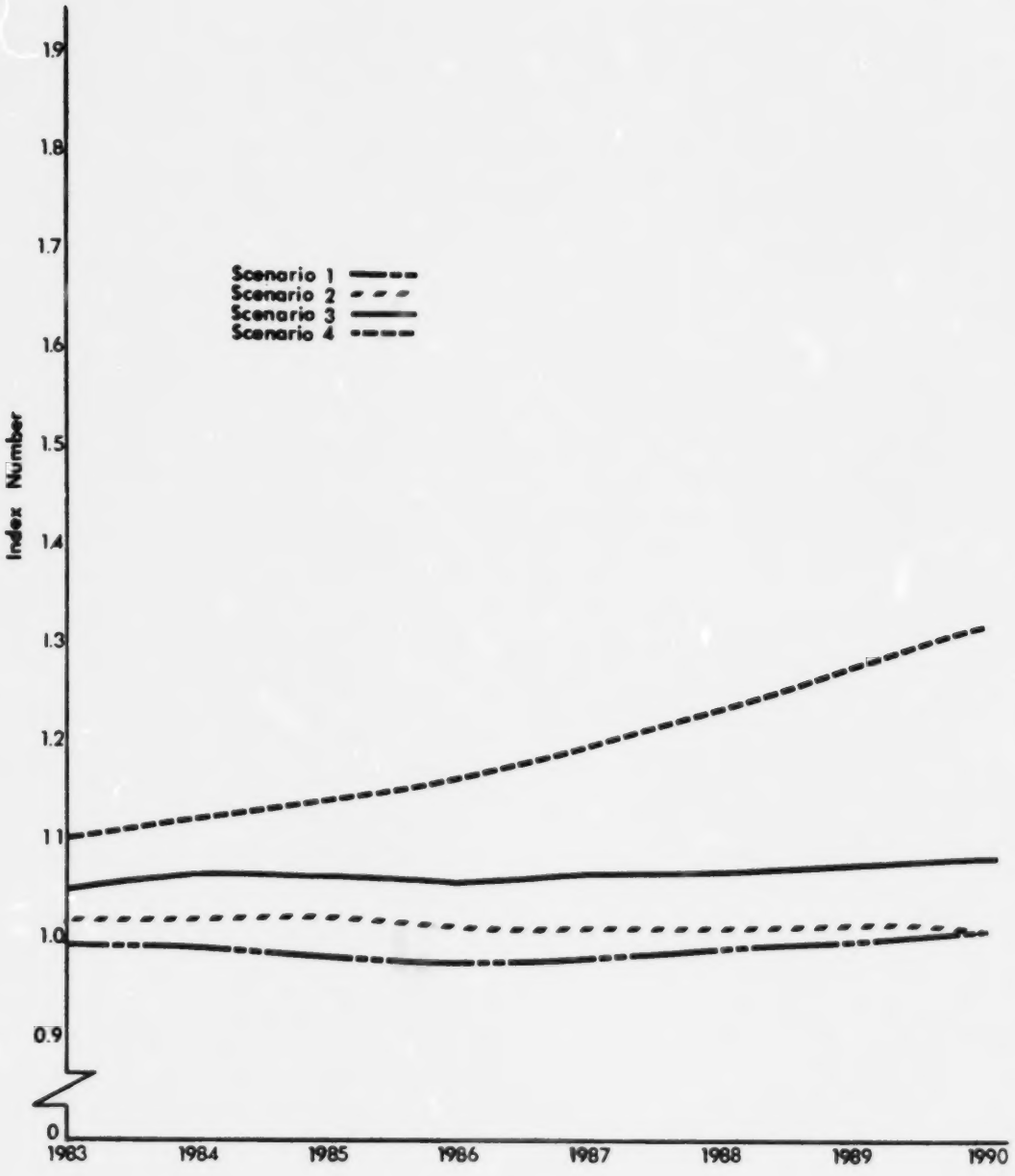
Year	Scenarios			
	1	2	3	4
1983	521.2	515.9	506.4	494.8
1984	534.9	533.8	528.6	519.1
1985	556.0	556.0	549.7	546.5
1986	582.4	581.3	575.0	579.2
1987	611.9	607.7	601.4	613.0
1988	643.6	634.1	627.7	645.7
1989	676.3	661.5	654.1	680.5
1990	705.8	686.8	681.5	715.3

The ratio of the quantity of oil used to real GNP shows the extent to which the economy is consuming oil. Figure 4.6 plots the computed ratios for the four price scenarios for the 1983-1990 period. Scenarios 1 and 2 show little movement in the ratio of barrels of oil to thousand 1971 dollars of real GNP. Only under low oil price scenarios 3 and 4 does the ratio exhibit significant movement in an upward direction. Greatly reduced oil prices would be expected to have this result.

The most interesting result was found to be the movement in the quantity of natural gas to GNP ratio, Qgas/GNP. Under all four scenarios the intensity of use of natural gas, that is, substitution of natural gas for other fuels, rises considerably. This results from the direct regulation of natural gas prices which are tied to the blended price of crude oil in Toronto. If the 65 percent price advantage of natural gas is retained, it is likely that natural gas will make significant market gains at the expense of other fuels. Under scenario Number 4, natural gas consumption per $1000 1971 GNP almost doubles by 1990. This is accomplished without the extension of natural gas service to the Atlantic provinces and Vancouver Island. The trend in this ratio is shown in Figure 4.7.

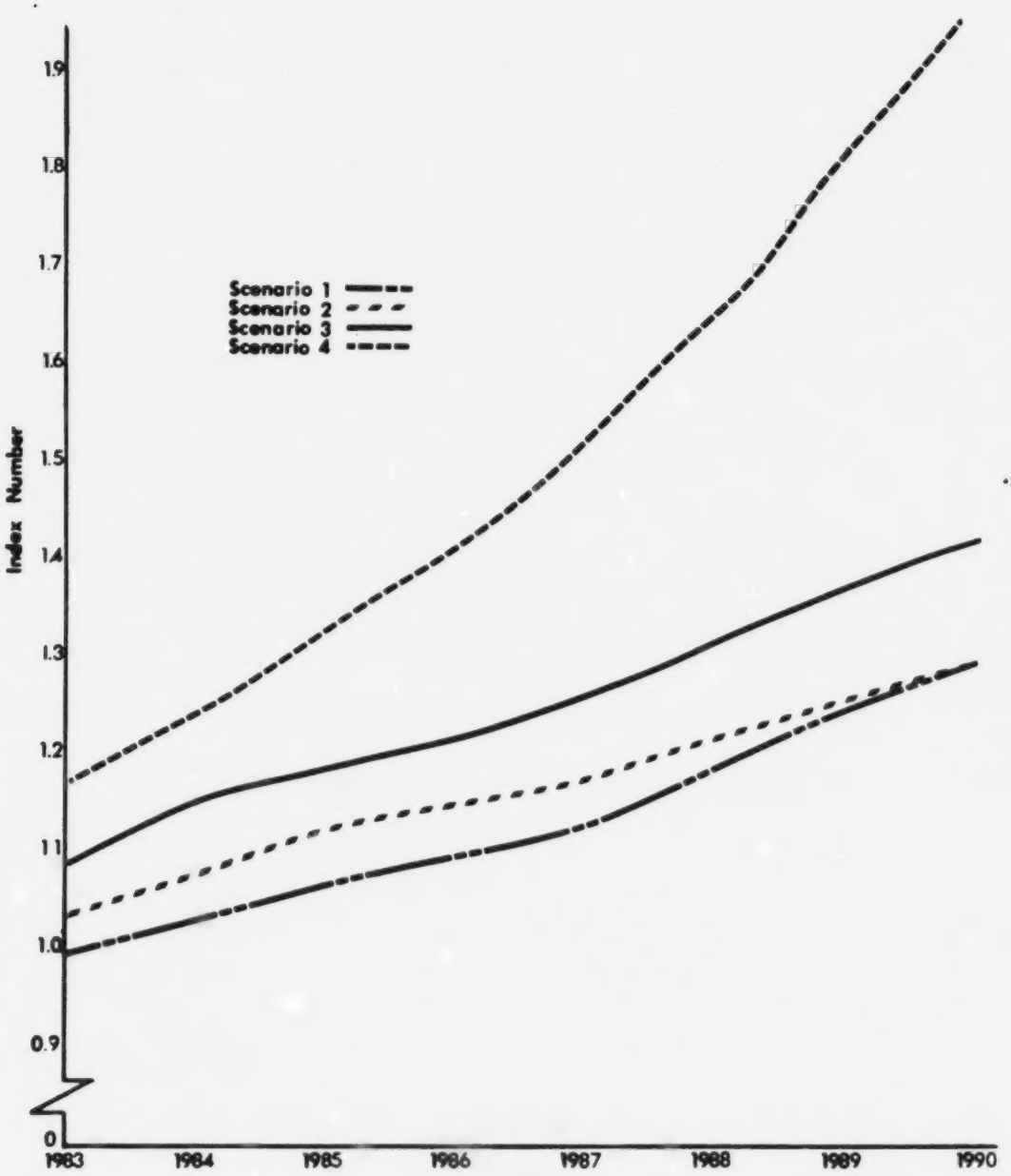
The ratio measuring the amount of electricity used, MW.h/$1000 1971 GNP (Qele/GNP), proved to be insensitive to the changing price scenarios. The ratio remained constant at 4 kW.h/GNP. Since traditionally, electricity consumption has closely tracked GNP, this result is not surprising.

These results show some significant trends with respect to inter-fuel substitution in Canada. Figure 4.8 shows the extent of forecast inter-fuel substitution indicated by the model simulations for each of the four price scenarios. These are market shares for final demand for energy in output joules which do not coincide with primary energy market shares due to various losses. They also reflect the energy conversion efficiencies typical in each end-use sector. The number of input joules required can be determined by dividing by the relevant conversion factors which are given in Appendix B.



Note: Index numbers are annual quantities divided by the 1983 value for Scenario 1.

FIGURE 4.6: GROWTH IN BARRELS OF CRUDE OIL CONSUMED/GNP.



Note: Index numbers are annual quantities divided by the 1983 value for Scenario 1.

FIGURE 4.7: GROWTH IN QUANTITY OF NATURAL GAS USED (MCF)/GNP.

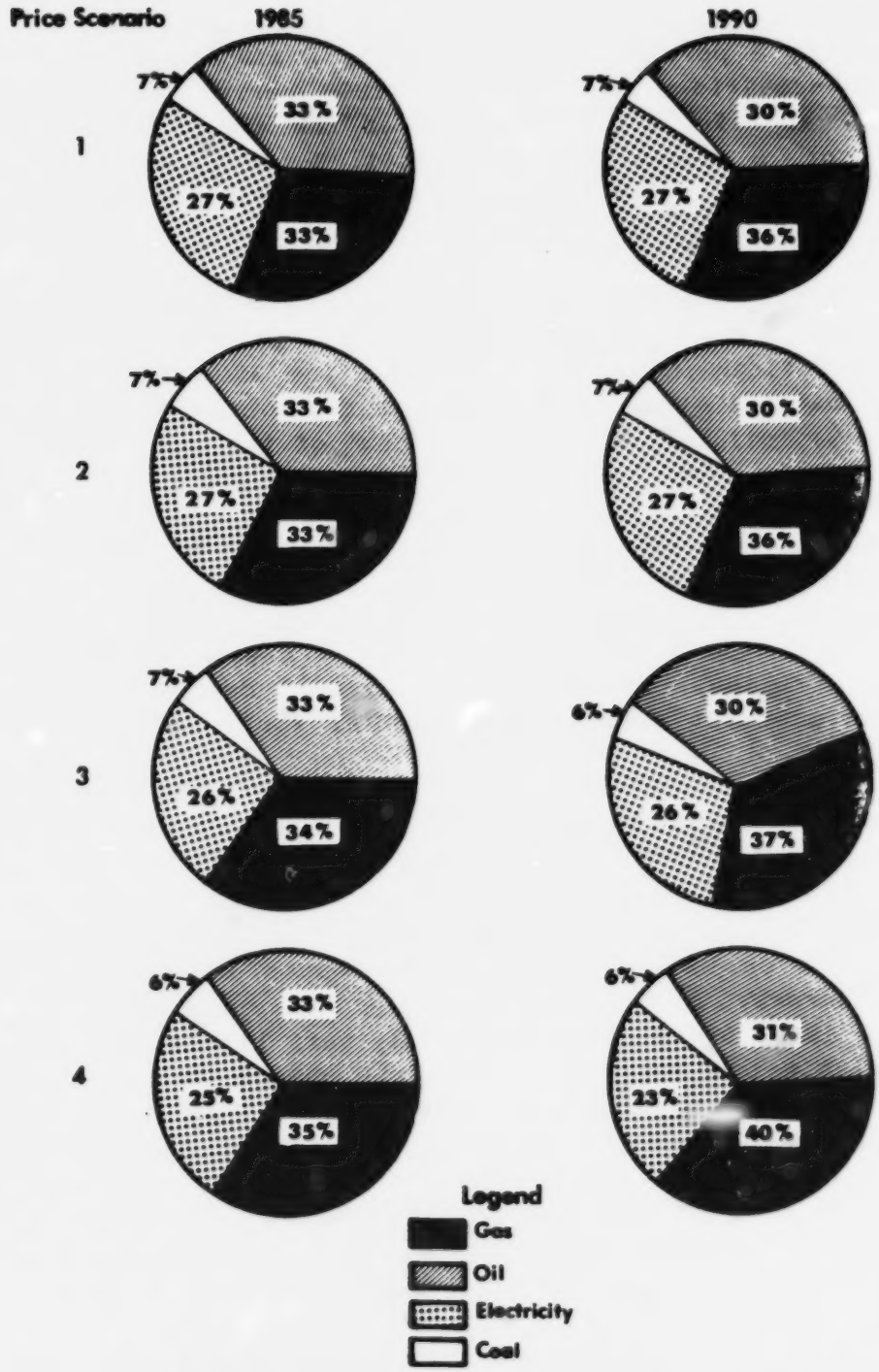


FIGURE 4.8: INTER-FUEL SUBSTITUTION IN CANADA

Figure 4.8 shows that under each scenario there is a response to rising relative energy prices. Oil's share declines by 3 percent in scenarios 1, 2 and 3 and by 2 percent in scenario 4 over the 1985-1990 period. Conversely, natural gas takes a larger share of the market in all four scenarios: 3 percent in scenarios 1, 2 and 3, and 5 percent in scenario 4. There is very little relative change in the shares of coal or electricity over the period.

These graphs clearly show that rising oil prices, in concert with the 65 percent natural gas parity rule, result in a significant inter-fuel substitution away from oil and towards natural gas. In the case of the most likely scenario (Number 2), oil relinquishes 3 percent of its market share to natural gas over the 1985-1990 period while coal and electricity shares remain constant.

4.7 Regional Energy Demands

The Mace model also provides a breakdown of energy demand by region. By looking at regional demand, the areas with the greatest growth and potential for substitution can be examined.

4.7.1 Atlantic Canada

The Atlantic provinces have traditionally been heavily dependent on imported crude oil, indigenous coal and to some extent on hydro electricity. Demand for coal in the region increases by 33 percent in the Mace model projections over the 1983-1990 period. Presently very little natural gas is available but this situation will change in the future. Table 4.11 shows the estimated demand for oil in output Btu's based on the four price scenarios. Each of the scenarios shows a very large increase in oil consumption over the decade (32 percent under scenario Number 2). Table 4.12 shows modest increases in demand for electricity in comparison to those for oil (19 percent under scenario Number 2).

In light of the historically high electricity costs this does not seem surprising. The absence of natural gas and the inconvenience of coal for many uses keeps oil in a position of prominence.

TABLE 4.11

TOTAL DEMAND FOR OIL IN ATLANTIC CANADA
(petajoules)

Year	Scenarios			
	1	2	3	4
1983	183.6	189.9	199.4	212.1
1984	189.9	198.3	212.1	228.9
1985	196.2	207.8	219.4	244.8
1986	202.6	213.1	226.8	262.7
1987	212.1	220.5	237.4	284.9
1988	223.7	231.1	249.0	311.2
1989	237.4	240.5	261.6	338.7
1990	250.0	250.0	273.3	360.8

TABLE 4.12

DEMAND FOR ELECTRICITY IN ATLANTIC CANADA
(petajoules)

Year	Scenarios			
	1	2	3	4
1983	91.8	91.8	90.7	90.7
1984	92.8	92.8	92.8	91.8
1985	95.0	95.0	95.0	93.9
1986	97.1	98.1	98.1	97.1
1987	101.3	102.3	102.3	101.3
1988	105.5	106.6	106.6	104.5
1989	109.7	110.8	110.8	107.6
1990	113.9	113.9	113.9	110.8

Figure 4.9 shows the percentage of secondary energy supplied by each of the three common fuels. The simulation using price scenario Number 2 shows that little inter-fuel substitution will occur in the Atlantic Region although a considerable increase in demand for energy does occur by 1990. This seems surprising in light of this region's reserves of indigenous coal and predictions by some analysts that a marked substitution between coal and oil will occur. (Coal is exogenously determined except for that amount used to generate electricity). Conversion of at least two Nova Scotia Power Corporation plants from oil to coal was envisaged in the Nova Scotia governments, "Energy - A Plan for Nova Scotia" of 1979. However, the Corporation has not yet announced any conversion plans.[6] It should be acknowledged that there is tremendous uncertainty regarding the start-up of natural gas supply and also delivery of Hibernia oil in the Maritimes. It may thus be reasonable to expect that energy consumers will be cautious when contemplating inter-fuel substitution.

Table 4.13 gives the annual quantities of generating fuels and primary electricity utilized under oil price scenario Number 2. Transmission losses and utility use are accounted for by electricity losses. Figure 4.10 shows the relative market shares for generating fuels in Atlantic Canada.

4.7.2 Quebec

The province of Quebec has a considerable hydro electric energy base but also depends heavily on crude oil and oil products and to a much lesser extent on natural gas. The natural gas distribution network is not as well developed as in provinces west of Quebec, although it is in the process of expansion.

Tables 4.14 through 4.16 show forecast demand for crude oil, natural gas and electricity in Quebec under the four pricing scenarios.

Figure 4.11 shows the change in final demand in market shares for the four fuels from 1985 to 1990 for price scenario Number 2. The reduction in oil prices has an effect

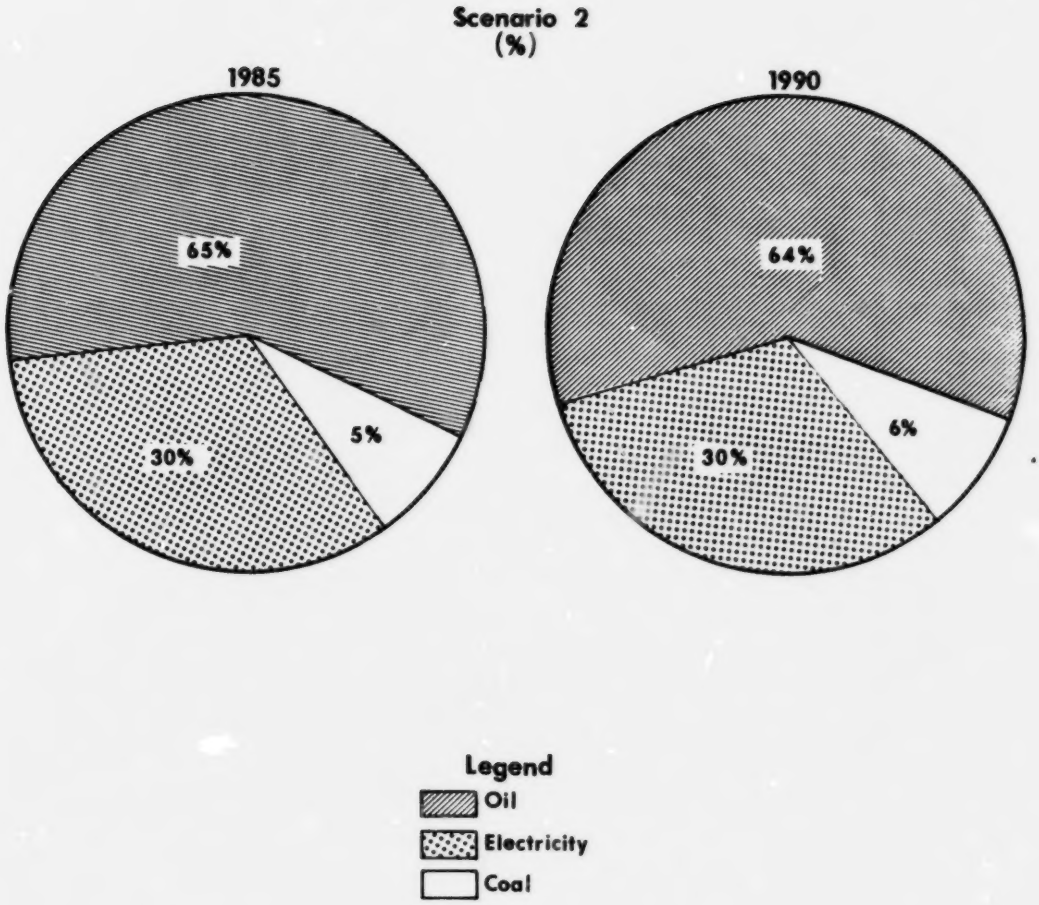


FIGURE 4.9: INTER-FUEL SUBSTITUTIONS IN ATLANTIC CANADA

TABLE 4.13

SOURCES OF ELECTRICITY IN ATLANTIC CANADA
(petajoules)

Year	Quantity of Hydro Electricity	Quantity of Secondary Electricity	Quantity of Oil Generated Electricity	Quantity of Coal Generated Electricity	Electricity Losses
1983	44.9	55.0	41.8	24.3	8
1984	45.9	55.6	43.4	24.3	9
1985	46.7	56.7	45.4	25.0	9
1986	47.7	59.3	45.4	25.9	9
1987	48.6	63.3	46.8	27.2	9
1988	49.6	66.4	49.4	28.5	10
1989	50.6	69.8	51.8	29.8	11
1990	51.6	73.2	53.4	30.8	11

NOTE: These projections result from a Mace simulation using oil price scenario 2.

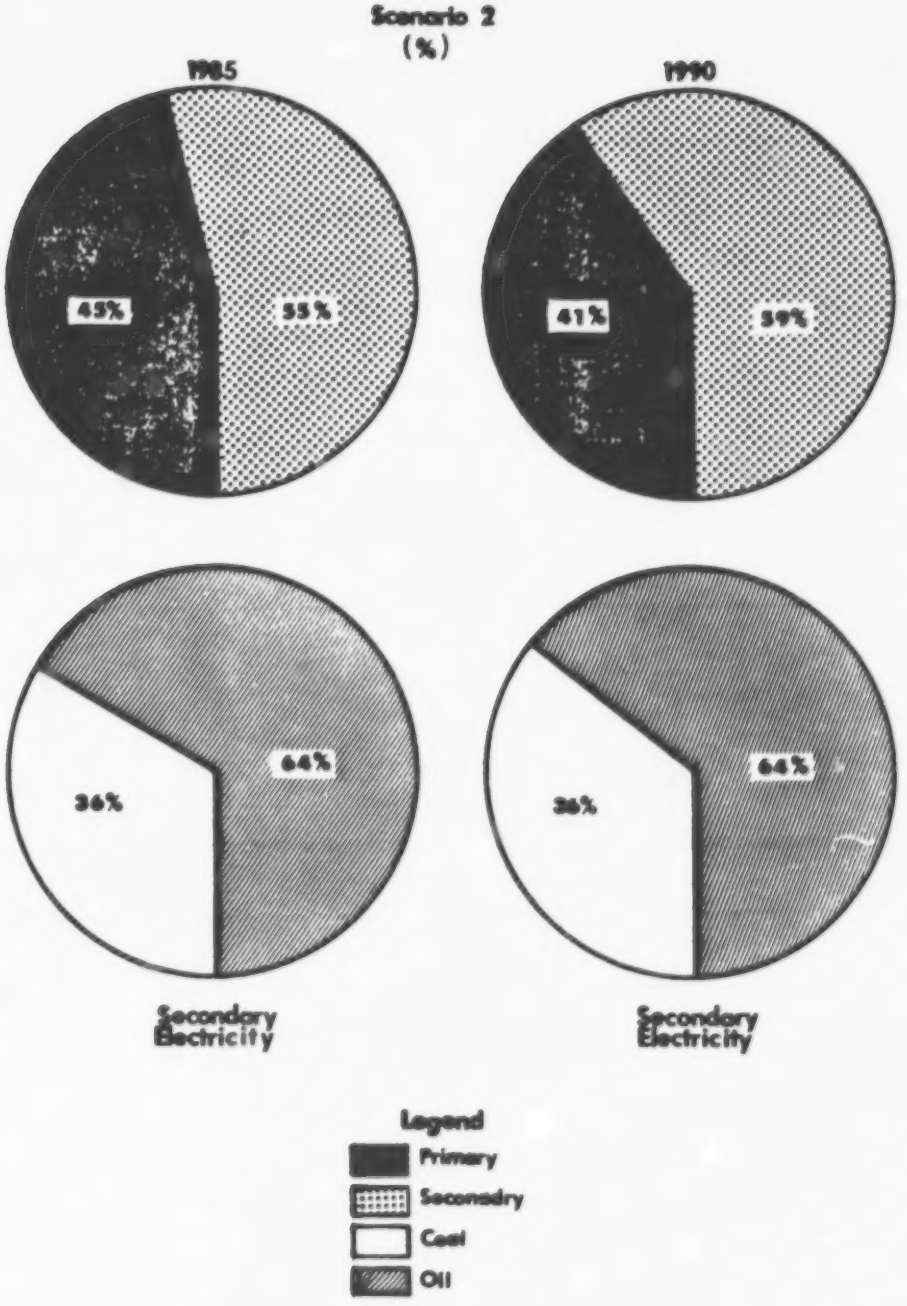


FIGURE 4.10 PRIMARY FUELS USED TO GENERATE ELECTRICITY, ATLANTIC CANADA.

TABLE 4.14

DEMAND FOR CRUDE OIL IN QUEBEC
(petajoules)

Year	Scenarios			
	1	2	3	4
1983	420.9	429.4	443.1	457.9
1984	429.4	441.0	458.9	480.0
1985	437.8	452.6	468.4	500.1
1986	446.3	462.1	480.0	523.3
1987	461.0	473.7	494.8	552.8
1988	477.9	488.5	511.7	584.5
1989	498.0	503.2	529.6	616.1
1990	517.0	514.8	545.4	643.6

TABLE 4.15

DEMAND FOR ELECTRICITY IN QUEBEC
(petajoules)

Year	Scenarios			
	1	2	3	4
1983	397.7	400.9	406.2	411.5
1984	405.1	409.3	415.7	424.1
1985	412.5	418.8	426.2	437.8
1986	423.1	430.4	438.9	455.8
1987	437.8	444.2	454.7	476.9
1988	454.7	460.0	470.5	498.0
1989	472.6	475.8	486.4	519.1
1990	489.5	489.5	502.2	540.2

TABLE 4.16

DEMAND FOR NATURAL GAS IN QUEBEC
(petajoules)

Year	Scenarios			
	1	2	3	4
1983	79.1	83.3	89.7	97.1
1984	83.3	88.6	98.1	108.7
1985	89.7	96.0	103.4	119.2
1986	95.0	100.2	108.7	128.7
1987	100.2	104.4	113.9	141.4
1988	106.6	109.7	120.3	155.1
1989	115.0	116.1	127.7	169.9
1990	122.4	122.4	136.1	185.7

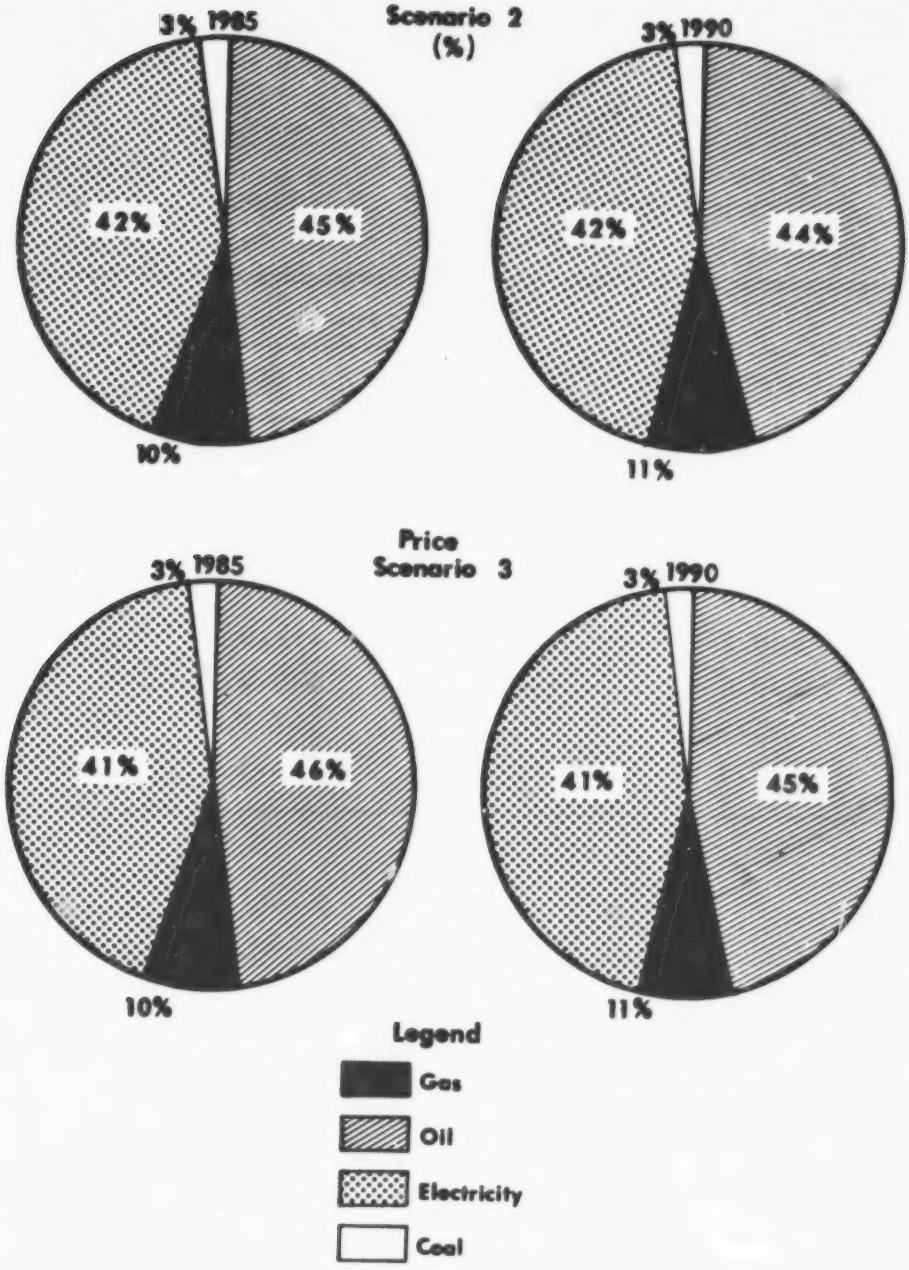


FIGURE 4.11: INTER-FUEL SUBSTITUTIONS IN QUEBEC

upon Quebec's oil conservation effort. While total energy consumed in the final demand sector rises considerably by 1990 (17 percent from 1985 to 1990 under scenario Number 2), the various energy shares do not change greatly.

Price scenario Number 2 generates a 20 percent increase in oil consumption in Quebec by 1990. Scenarios 1 and 3 differ only marginally in the levels of increase, but scenario 4 produces a 41 percent increase in oil use.

The significance of electricity in Quebec is made clear by its close approximation to oil's share of the market. This is evident in Figure 4.11. Scenario 2 shows electricity growth of 22 percent by 1990. As was the case in the simulations of electricity demand in Atlantic Canada, Quebec electricity demand increases only marginally in response to lower oil prices.[7] The lowest oil price scenario (4) generates 51 petajoules more consumption of electricity by 1990 than does scenario 2 (although electricity's share falls from 42 percent to 38 percent).

The limited natural gas distribution network in Quebec (as well as stiff competition from heavy fuel oil) results in a much lower market penetration relative to oil and electricity. By 1985, gas supplies only 10 percent of all final demand. However, under scenario 2, natural gas demand rises by 47 percent by 1990.

Figure 4.11 shows projected inter-fuel substitution for price scenarios 2 and 3. Under price scenario 2 some substitution of natural gas for crude oil is evident (1 percentage point), over the period 1985-1990. Electricity does not penetrate oil's market to any extent.

Under scenario 3 substitution between gas and oil is again evident but it is not extensive.

No significant amount of secondary electricity is generated in Quebec. Therefore a breakdown of primary energy used to generate electricity has not be provided.

4.7.3 Ontario

The province of Ontario is Canada's largest user of energy. It consumes large amounts of natural gas and oil, and it has a large capacity to generate primary electricity. Table 4.17 shows the forecast increase in oil consumption under each of the four scenarios. Both scenarios 1 and 2 suggest that only marginal increases in oil consumption will take place by 1990. Under scenario 2, oil consumption increases by 14.7 petajoules per year in 1990 relative to 1983 (a 3 percent increase).

Scenarios 3 and 4 generate much greater increases in oil consumption with scenario 4 implying a 29 percent increase by 1990 over the 1983 (high cost) estimate. The most likely pricing assumption (2) should, in view of the real oil price decline, be gratifying to those concerned about reducing oil dependence in Canada because oil consumption increases by only 3 percent by 1990. However, the NEP '10 percent' reduction referred to in Chapter 1 would, of course, be all the more difficult to achieve.

Table 4.18 shows electricity demand in Ontario. Significant levels of growth are evident under all four oil price scenarios. As in the Atlantic Provinces and Quebec forecasts, declining oil prices generate increased demand for electricity. Scenario 2 produces a 30 percent increase in electricity demand by 1990. Scenarios 3 and 4 generate 31 percent and 36 percent increases, respectively. The average annual growth rate for scenario 2 from 1985 to 1990 is approximately 4.16 percent. This is lower than the historical growth rate of the 1960s and 1970s of 6 to 7 percent, but higher than other forecast growth rates.

Table 4.19 provides forecasts of natural gas demand in Ontario. Each scenario generally produces large annual increases in demand for gas. Keeping in mind the fact that the price of natural gas is tied directly to the blended price of oil, Table 4.19 shows very healthy increases for each lower price scenario. Scenario 1 shows a 60 percent annual increase by 1990, Number 2 a 54 percent by 1990 (6.3 percent annual average growth rate), Number 3 a 60 percent (starting from a higher level of consumption in 1983) and

TABLE 4.17

DEMAND FOR CRUDE OIL IN ONTARIO
(petajoules)

	Scenarios			
Year	1	2	3	4
1983	447.3	456.8	470.5	486.4
1984	448.4	460.0	479.0	501.1
1985	449.4	464.2	481.1	511.7
1986	449.4	464.2	482.1	524.3
1987	452.6	465.3	485.3	538.1
1988	457.9	466.3	488.5	551.8
1989	463.1	466.3	490.6	562.3
1990	471.6	471.6	498.0	575.0

TABLE 4.18

DEMAND FOR ELECTRICITY IN ONTARIO
(petajoules)

	Scenarios			
Year	1	2	3	4
1983	398.8	399.8	402.0	404.1
1984	407.2	410.4	414.6	417.8
1985	417.8	423.1	428.3	434.7
1986	432.6	438.9	445.2	455.8
1987	451.5	457.9	465.3	479.0
1988	473.7	477.9	486.4	503.2
1989	496.9	499.0	507.5	526.4
1990	519.1	519.1	527.5	547.5

TABLE 4.19

DEMAND FOR NATURAL GAS IN ONTARIO
(petajoules)

	Scenarios			
Year	1	2	3	4
1983	621.4	642.5	674.1	713.2
1984	659.4	687.9	732.2	789.1
1985	700.5	736.4	775.4	860.9
1986	740.6	775.4	822.9	944.2
1987	790.2	821.8	878.8	1045.5
1988	854.6	878.8	945.3	1164.7
1989	930.5	942.1	1018.1	1297.7
1990	992.8	991.7	1078.2	1392.6

Number 4 a 95 percent increase by 1990. These results indicate that significant inter-fuel substitution may occur by 1990.

The market shares for final demand for energy in Ontario are shown in Figure 4.12. Under scenario 2 a significant substitution away from oil (in terms of market shares) occurs by 1990. Oil's market share falls 4 percent from 1285 to 1990 while those for electricity and natural gas increase by 1 percent and 4 percent, respectively. Coal's market share falls by 1 percent by 1990.

Ontario has a large primary electricity generating capacity. However, a portion of electricity used is generated by thermal units. Table 4.20 shows the breakdown of electricity generation and fuels used. Figure 4.13 shows the relative market shares of fuels used to generate electricity. Primary electricity declines in importance slightly by 1990 but still supplies approximately 80 percent of total requirements (net of losses). Secondary electricity remains largely coal-fired (nuclear electricity is defined in Mace as being primary electricity).

4.7.4 The Prairie Region

The Prairie region (Manitoba, Saskatchewan, and Alberta) has traditionally been more dependent on natural gas than the other regions of Canada. However, there remains some scope for increasing the extent of the distribution systems to further reduce the use of oil in non-transportation modes. Natural gas will remain prominent in the energy mix for many years to come. Table 4.21 shows forecasts of crude oil demand on the Prairies in Canada. Scenario 1 generates only an 11 percent increase by 1990 (annual average growth rate of 1.1 percent) with very low levels of growth in the years 1983-86. Scenario 3 has oil consumption rising somewhat faster, but at levels far below those typical of the past.

Table 4.22 provides estimates of growth in electricity demand. Scenarios 1, 2 and 3 give virtually the same result, estimating an approximately 26 percent increase in electricity consumption by 1990.

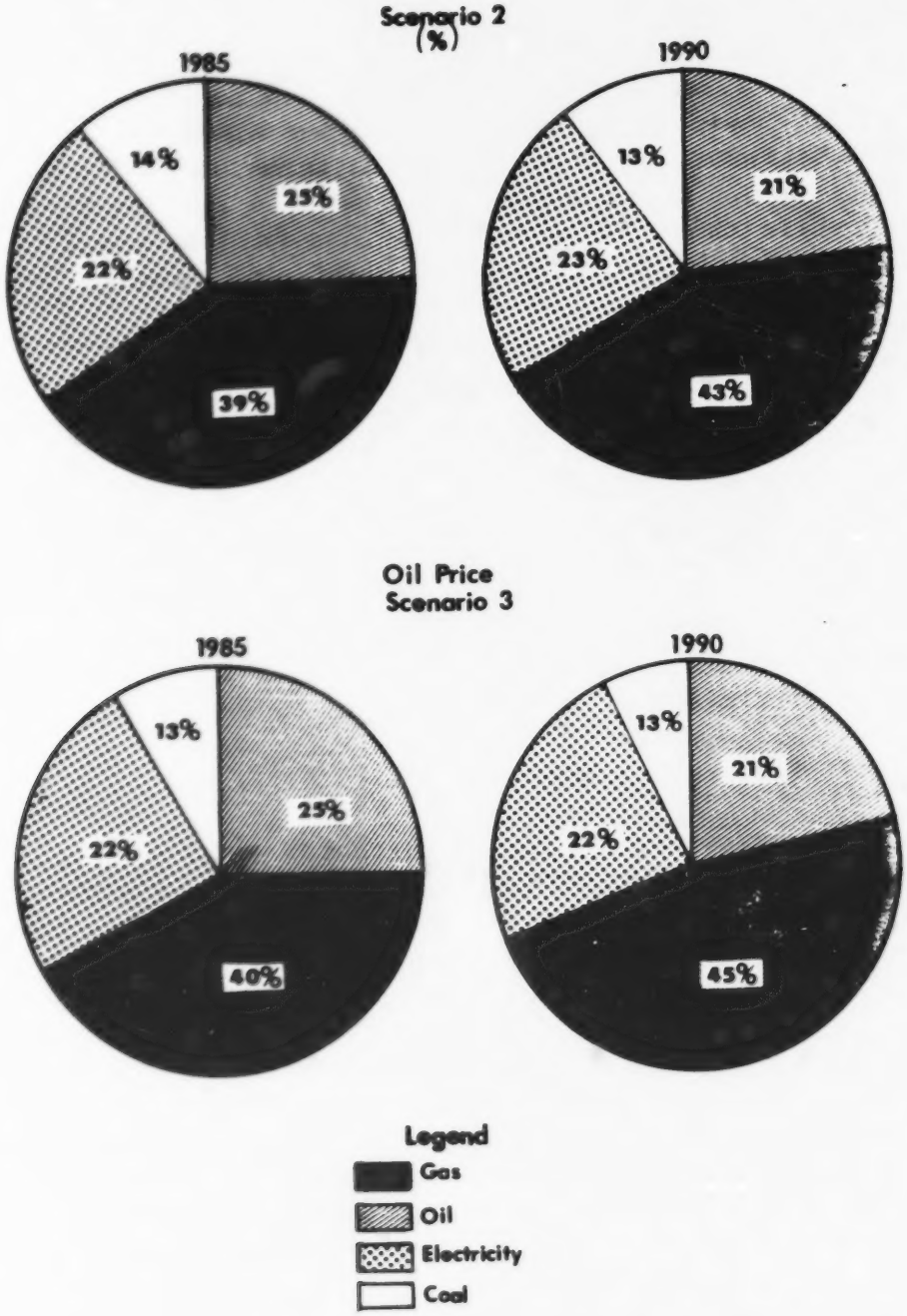


FIGURE 4.12: INTER-FUEL SUBSTITUTIONS IN ONTARIO

TABLE 4.20

PRIMARY FUELS USED TO GENERATE ELECTRICITY IN ONTARIO
(petajoules)

Year	Quantity of Hydro Electricity	Quantity of Secondary Electricity	Quantity of Natural Gas-Generated Electricity	Quantity of Coal-Generated Electricity	Electricity Losses
1983	362.9	74.9	16.9	72.8	36
1984	373.5	74.9	16.9	72.1	40
1985	385.1	77.0	17.9	87.6	40
1986	396.7	83.3	17.9	91.8	40
1987	408.3	91.8	19.0	98.1	43
1988	420.9	102.3	21.1	104.4	43
1989	433.6	112.9	24.3	111.8	47
1990	446.3	120.3	25.3	116.1	47

NOTE: These projections result from a Mace simulation using oil price scenario 2. The quantity of hydro electricity includes nuclear generated electricity.

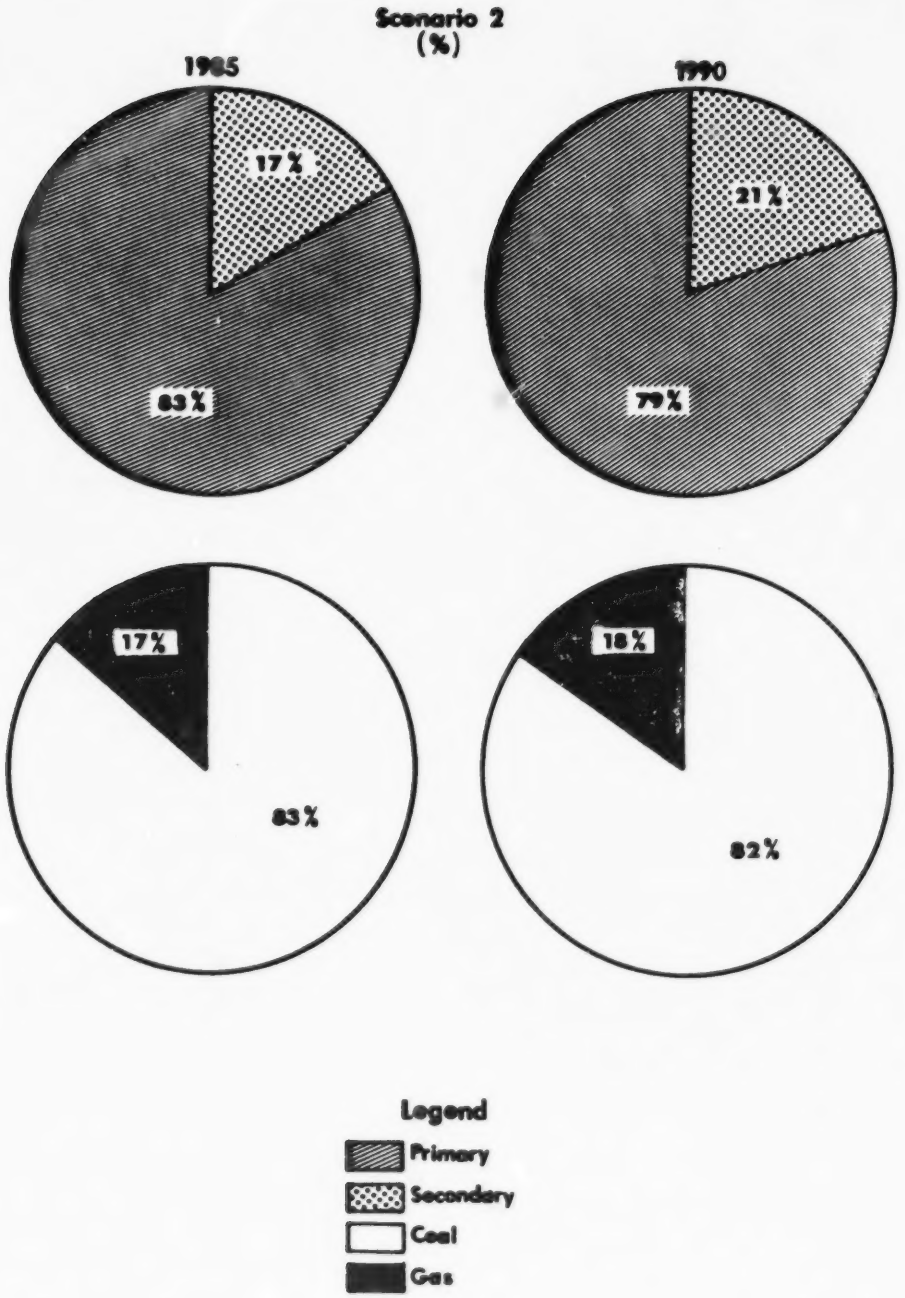


FIGURE 4.13: PRIMARY FUELS USED TO GENERATE ELECTRICITY IN ONTARIO

TABLE 4.21

DEMAND FOR CRUDE OIL, PRAIRIE REGION
(petajoules)

Year	Scenarios			
	1	2	3	4
1983	249.0	253.2	260.6	268.0
1984	249.0	256.4	265.9	276.4
1985	251.1	259.5	268.0	283.8
1986	252.1	260.6	271.1	292.2
1987	257.4	264.8	276.4	304.9
1988	262.7	268.0	289.6	315.4
1989	268.0	271.1	283.8	326.0
1990	276.4	275.4	291.2	336.5

TABLE 4.22

DEMAND FOR ELECTRICITY, PRAIRIE REGION
(petajoules)

Year	Scenarios			
	1	2	3	4
1983	183.6	183.6	182.5	180.4
1984	186.7	186.7	185.7	184.6
1985	191.0	191.0	192.0	191.0
1986	197.3	198.3	199.4	198.3
1987	205.7	206.8	206.8	206.8
1988	214.2	215.2	216.3	214.2
1989	223.7	223.7	223.7	220.5
1990	232.1	232.1	232.1	225.8

It is interesting to note that scenario 4 generates smaller levels of electricity consumption than scenarios 2 and 3. This implies that substitution between oil and electricity is occurring. As the price of oil falls lower, smaller increases in electricity demand are occurring. These results are opposite to those noted in previous sections.

Levels of electricity demand appear quite insensitive to the large declines in oil prices under all four scenarios.

Table 4.23 shows the estimates for natural gas consumption on the Prairies. The first scenario yields a 42 percent increase in consumption during the forecast period, while the fourth yields a 71 percent increase by 1990. Natural gas clearly retains its prominence on the Prairies under all scenarios. Figure 4.14 summarizes substitution effects for the four fuels.

Some inter-fuel substitution effects occur in the Prairie region over the forecast period. Under scenario 2, electricity retains its share of the total energy market but coal and natural gas expand theirs at the expense of crude oil products. Between 1985 and 1990 oil's share falls by 3 percent while natural gas gains 2 percent and coal 1 percent. Under scenario 3, with lower oil prices, natural gas still grows by 2 percent, coal by 1 percent, but electricity loses 1 percent while oil's share falls by 2 percent.

Although Manitoba has a large hydroelectric generation capacity (supplemented by two major coal-fired plants), both Saskatchewan and Alberta are primarily dependent on thermally generated electricity. Table 4.24 provides a breakdown of primary and secondary electricity generation and the primary energy fuels required to generate secondary electricity. Figure 4.15 shows the relative percentages of market share for the generation sector on the Prairies. Fully two-thirds of electricity generation will be of a thermal nature in 1985. By 1990 this will rise to 70 percent. Of the secondary electricity produced in 1985, 36 percent will be natural-gas-fired, while 64 percent will be coal-fired. By 1990 coal's percentage will rise to 66 percent.

TABLE 4.23

DEMAND FOR NATURAL GAS, PRAIRIE REGION
(petajoules)

Year	Scenarios			
	1	2	3	4
1983	515.9	532.8	558.1	589.7
1984	540.2	562.3	597.1	640.4
1985	567.6	594.0	622.5	685.8
1986	591.9	616.1	648.8	736.4
1987	621.4	642.5	681.5	797.6
1988	659.4	674.1	719.5	870.4
1989	700.5	709.0	760.7	947.4
1990	734.3	733.2	792.3	1010.7

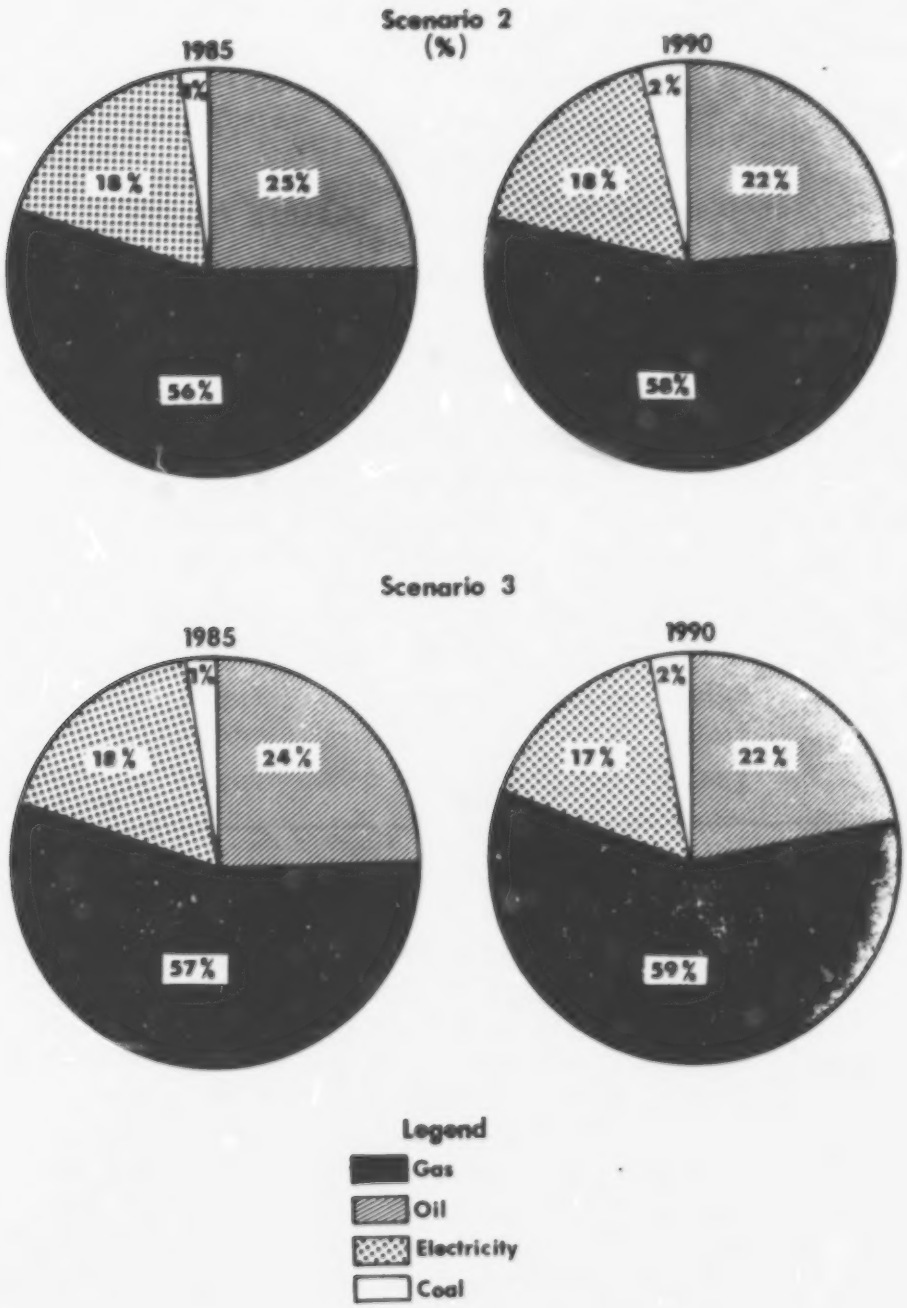


FIGURE 4.14: INTER-FUEL SUBSTITUTIONS, PRAIRIE REGIONS

TABLE 4.24

PRIMARY FUELS USED TO GENERATE ELECTRICITY, PRAIRIE REGION
(petajoules)

Year	Quantity of Hydro Electricity	Quantity of Secondary Electricity	Quantity of Natural Gas-Generated Electricity	Quantity of Coal-Generated Electricity	Electricity Losses
1983	69.6	140.3	54.9	109.7	25
1984	70.7	142.4	59.1	109.7	25
1985	71.7	146.6	63.3	110.8	29
1986	73.9	153.0	59.1	117.1	29
1987	74.9	161.4	60.1	122.4	29
1988	77.0	168.8	64.4	126.6	29
1989	78.1	177.2	69.6	129.8	29
1990	79.1	185.7	69.6	134.0	32

NOTE: These projections result from a Mace simulation using oil price scenario 2.

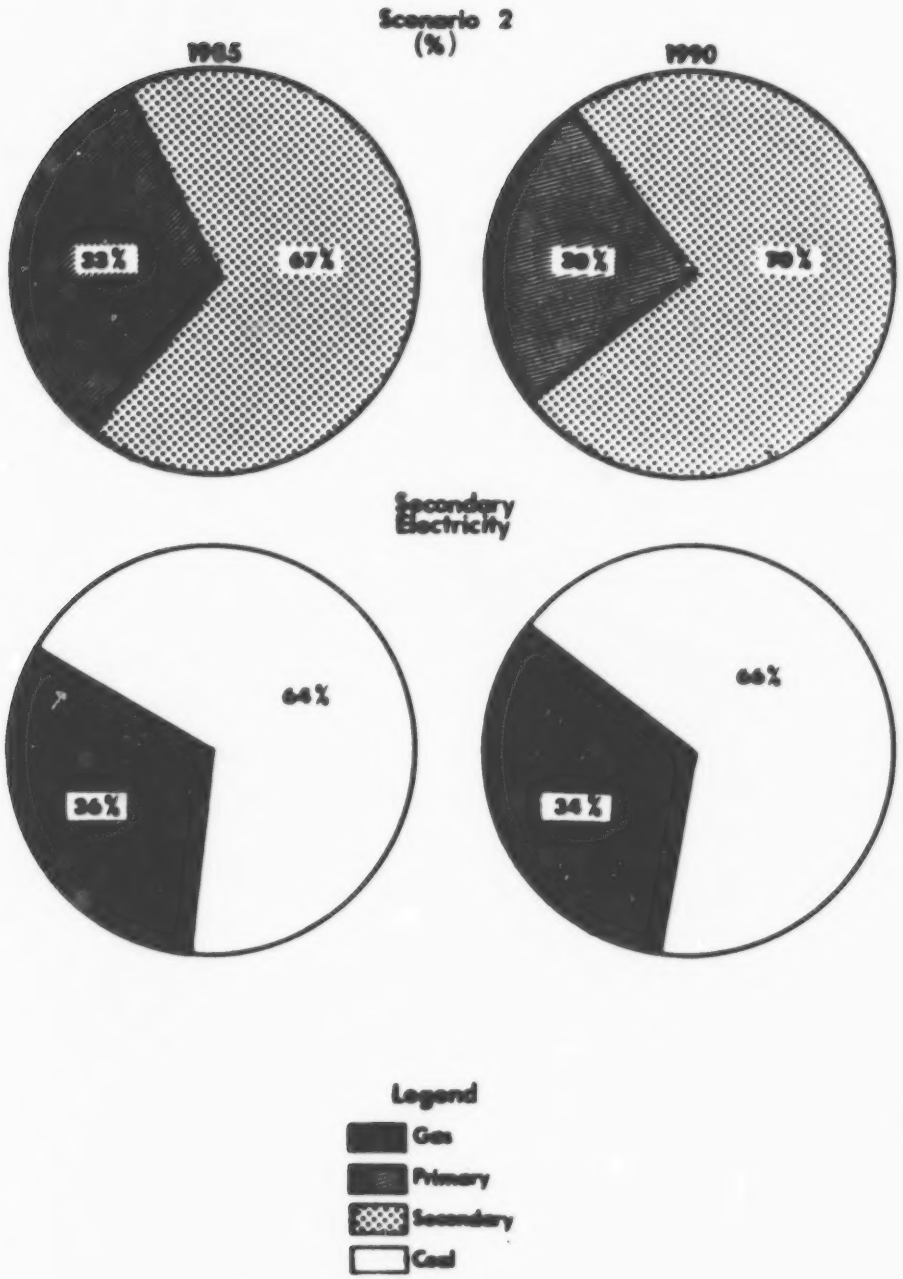


FIGURE 4.15: PRIMARY FUELS USED TO GENERATE ELECTRICITY, PRAIRIE REGION.

4.7.5 British Columbia and the Territories

British Columbia is uniquely endowed with large amounts of natural gas, hydro-generated electricity, and coal deposits. For this reason the shares of the three most important fuel forms are more nearly equal than in any other region.

Only small amounts of coal are used in final demand in B.C. and the Territories. An increase of 29 percent is predicted by 1990. This would be for increased industrial use such as plant process heat.

Crude oil consumption (Table 4.25) is expected to rise under scenario 2 but at low rates. The scenario 2 assumptions lead to an increase in oil consumption by 1990 of 13 percent (to 208 petajoules per year.) This represents an average annual growth rate of 1.8 percent per year between 1983 and 1990. Scenario 3 produces slightly greater increases but the scenario 4 increases (28 percent by 1990) are considerably higher than those predicted under scenario 2.

Electricity consumption in British Columbia (Table 4.26) is fairly insensitive to the oil price reduction scenarios. In 1983 the difference between the lowest estimate and the highest is only 2.1 petajoules. In 1990 the difference is only 6.3 petajoules. Once again, the lower oil prices fall the higher electricity demand goes, indicating oil-electricity complementarity rather than substitutability. Under scenario 2 electricity demand rises 11 percent by 1990.

Natural gas use in B.C. is very responsive to declining oil prices (and thus its own price) as evidenced by the difference between scenarios 2 and 4. Scenario 2 produces a 38 percent increase in demand by 1990, scenario 4 a 70 percent increase (see Table 4.27).

Of significant interest is the extent of inter-fuel substitution among the four energy forms. Figure 4.16 shows the change from 1985 to 1990 generated by oil price scenario 2. Natural gas gains by 3 percent at the expense of coal, electricity and crude oil. Under price scenario Number 3,

TABLE 4.25

DEMAND FOR CRUDE OIL, BRITISH COLUMBIA
(petajoules)

	Scenarios			
Year	1	2	3	4
1983	180.4	183.6	188.8	194.1
1984	181.5	186.7	193.1	201.5
1985	184.6	189.9	196.2	207.8
1986	186.7	192.0	199.4	214.2
1987	192.0	196.2	203.6	223.7
1988	197.3	200.5	208.9	233.2
1989	202.6	203.6	213.1	241.6
1990	207.8	207.8	218.4	249.0

TABLE 4.26

DEMAND FOR ELECTRICITY, BRITISH COLUMBIA
(petajoules)

	Scenarios			
Year	1	2	3	4
1983	158.3	159.3	159.3	160.4
1984	159.3	160.4	161.4	162.5
1985	159.3	161.4	162.5	164.6
1986	161.4	163.5	165.6	167.7
1987	165.6	166.7	168.8	172.0
1988	168.8	170.9	172.0	176.2
1989	173.0	174.1	175.1	179.4
1990	176.2	176.2	178.3	182.5

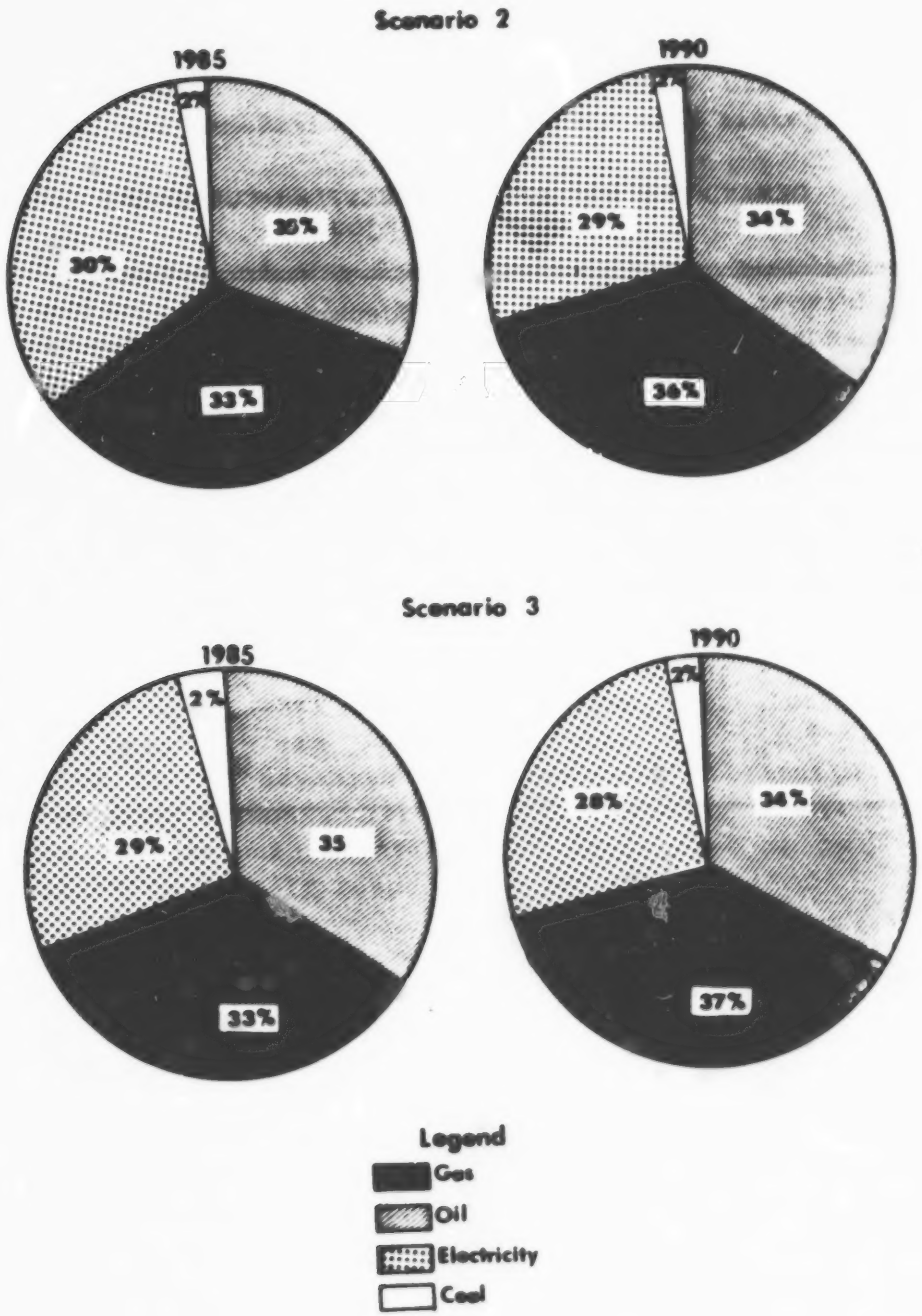


FIGURE 4.16: INTER-FUEL SUBSTITUTIONS , B.C.

TABLE 4.27

DEMAND FOR NATURAL GAS, BRITISH COLUMBIA
(output petajoules)

Year	Scenarios			
	1	2	3	4
1983	155.1	159.3	165.6	174.1
1984	162.5	167.7	177.2	187.8
1985	169.9	177.2	184.6	200.5
1986	176.2	183.6	192.0	215.2
1987	184.6	191.0	202.6	233.2
1988	196.2	201.5	214.2	254.3
1989	208.9	211.0	225.8	277.5
1990	220.5	219.4	236.3	295.4

natural gas increases its share even more, by a total of 4 percent over the same period. Under this scenario, electricity and crude oil both suffer a reduced market share.

In British Columbia virtually all electricity is primary electricity. Therefore, no amounts of oil, gas or coal are used for generation purposes under this assumption.

4.8 General Simulation Results

The results of the four price scenario simulations reveal important implications for federal and provincial energy policies. Rather than severe downturns in consumption, typical of 1981-1982, the Mace model predicts that, based upon energy policies in force at the time of writing, oil consumption will not be drastically reduced. In fact, due to the declining oil price increases, crude oil holds its own in terms of market shares. This runs counter to the national energy policy objective of reducing oil use to 10 percent of total energy demand in the residential, commercial and industrial sectors.

It is clear that there is strong substitution of natural gas in all areas where it is available. This is clearly shown by the advances in natural gas utilization in the four western regions. Preferential pricing of natural gas outside the producing provinces at 65 percent of commodity equivalent is largely responsible for these gains.

An interesting question to ask is whether this trend can be maintained in the future. Strong economic arguments can be made for a country wishing to become self-sufficient in oil raising its domestic oil prices to the world level. This would have the effect of contributing to conservation of both oil and gas, and probably substitution of electricity, coal and other alternatives in place of oil. The implications of dissolving the 75 percent cap on old oil will be discussed in the next chapter.

Footnotes

[1]John F. Helliwell et al, Energy and the National Economy: An Overview of the Mace Model, Resources Paper 89 (Vancouver: Department of Economics, University of British Columbia, March 1983).

[2]There are other variables which are an important part of the Mace model but which are determined exogenously. Energy transportation tariffs are one such example. These are set to grow annually at the forecast rate of domestic inflation.

[3]See Appendix C for tables of five-year price elasticities.

[4]"Focus Changes in Oil Spending," The Financial Post, February 26, 1983, p. 1.

[5]The E/GDP ratio used in Chapter 3 was determined by using millions of tons of oil equivalent and Gross Domestic Product while Mace uses aggregated output Btu and Gross National Product to generate Btu/GNP.

[6]John Dawson, Development Options for Maritime Coal, Working Paper 83-1 (Calgary: Canadian Energy Research Institute, January 1983), p. 26.

[7]Reductions in the price of oil might be expected to reduce the demand for electricity which, here, it does not. Robert McRae explains that the reduced oil price causes an income effect which increases the overall demand for electricity. (R. N.) McRae, "Primary Energy Demand in Canada," Energy Economics, October 1979, pp. 203-10.

Chapter 5

CANADIAN ENERGY CONSUMPTION UNDER WORLD PRICES

The blended price of domestic oil is a volume--weighted average of three prices: old, special old and the new oil reference prices. Because a large percentage of domestic oil produced qualifies for only the old oil price, the blended price (the price refiners pay for oil) is close to 75 percent of the landed cost of imported oil. This means user oil product prices are below world levels (perhaps close to 90 percent after Canadian ownership charges, refinery margins and petroleum compensation charge and taxes are added).

The decline in international oil price levels recently registered provides an opportunity to raise Canadian oil prices to international levels. Although it is far from certain that this will happen, it was felt useful to simulate removal of 75 percent cap on old oil. This was done for pricing scenarios 1, 2 and 3. Analysis of the results, which are discussed in this chapter, indicates that removal of the cap would have the effect of strengthening oil conservation and inter-fuel substitution effects and of increasing government and industry revenues.

5.1 Canadian Consumption

Table 5.1 shows the effect on energy consumption of removing the 75 percent cap in 1984 for the oil price scenarios 1, 2, and 3. If these estimates are compared with those in Table 4.2 in Chapter 4, it will be noted that total energy demand declines slightly as the domestic oil price is increased. Under the most likely scenario (2), consumption in 1986 is 2.2 percent lower. By 1990, consumption is 1.7 percent lower.

TABLE 5.1

TOTAL FINAL ENERGY DEMAND IN CANADA
(petajoules)

Year	Scenario		
	1	2	3
1983	4084.0	4167.0	4290.0
1984	4112.0	4234.0	4411.0
1985	4223.0	4373.0	4533.0
1986	4349.0	4494.0	4685.0
1987	4521.0	4651.0	4872.0
1988	4741.0	4839.0	5087.0
1989	4996.0	5043.0	5316.0
1990	5236.0	5229.0	5537.0

TABLE 5.2

QUANTITY OF OIL DEMANDED IN CANADA
($10^6 m^3$)

Year	Scenarios		
	1	2	3
1983	83.4	85.3	88.3
1984	82.6	85.2	89.3
1985	83.6	86.7	90.2
1986	84.5	87.7	91.7
1987	86.4	89.1	93.9
1988	89.1	91.0	96.3
1989	92.2	93.1	98.7
1990	95.5	95.3	101.7

TABLE 5.3

QUANTITY OF NATURAL GAS DEMANDED IN CANADA
($10^9 m^3$)

Year	Scenarios		
	1	2	3
1983	51.9	53.9	56.9
1984	52.7	55.2	59.2
1985	55.8	58.8	62.1
1986	58.3	61.1	65.1
1987	61.5	64.0	68.7
1988	65.8	67.7	73.2
1989	70.9	71.8	78.0
1990	75.5	75.6	82.7

TABLE 5.4

QUANTITY OF ELECTRICITY DEMANDED IN CANADA
(10^9 kW.h)

Year	Scenarios		
	1	2	3
1983	342.0	343.0	345.0
1984	346.0	349.0	352.0
1985	352.0	356.0	361.0
1986	362.0	367.0	372.0
1987	375.0	380.0	386.0
1988	390.0	394.0	400.0
1989	407.0	409.0	415.0
1990	423.0	423.0	430.0

Table 5.2 shows estimates for final demand for oil in Canada. Under scenario 2, consumption of crude oil in 1985 is 2.5 percent lower, while in 1990 it is 2 percent lower.

Because natural gas prices are tied to the blended price of crude oil, removal of the 75 percent cap would also result in a significant increase in gas prices. Table 5.3 shows estimates for total Canadian natural gas consumption, which are marginally less than those in Chapter 4. Demand in scenario 2 is lower by 3.3 percent in 1986 and 2.5 percent in 1990 relative to the estimates found in the preceding chapter.

Table 5.4 provides estimates of electricity demand for Canada. These show a marginal decline from the estimates presented in Chapter 4 (see Table 4.5).

Overall, these estimates indicate that removing the price restriction on old oil would have a significant effect upon reduction of oil consumption in Canada. Furthermore, this would have a positive effect upon industry and government revenues. Moving all oil prices to opportunity cost levels would make up, to some extent, for the moderation in internationl oil prices and the concomitant inability to push through all the scheduled government pricing increases.

Chapter 6

UNCONVENTIONAL ALTERNATIVE FUELS IN CANADA

6.1 Introduction

In Chapter 2 it was pointed out that modern industrial economies make use of four basic types of fuel: coal, crude oil and products, natural gas, and electricity. This list, however, does not include all those forms of energy which are used or could conceivably be used. It is generally expected that other types of fuels will enter Canada's energy economy to a more significant extent than in the past. These are generally known as unconventional alternative fuels, and alternative transportation fuels (ATF).

Chapters 4 and 5 used a model simulation approach to estimate the extent to which inter-fuel substitution would likely occur among the four conventional fuels as the result of oil price changes. This approach cannot be used to estimate penetration of the alternatives because of a lack of historical data for modelling purposes. Attempting to forecast penetration of the alternatives is, therefore, navigation in uncharted waters. Cost and supply estimates can be produced but even favourable economics evaluations do not ensure that consumers will utilize an alternative energy fuel or technology to a significant degree. The objective of this chapter is to identify alternative fuels, and to evaluate the potential for substituting them in place of conventional oil-based fuels.

6.2 Transportation Sector

The mobile nature of transportation vehicles makes some types of fuel more suitable than others. Currently, most vehicles use liquid fuels such as gasoline, diesel fuel, fuel oil, or turbo fuels. Implementing alternative fuel use programs can be approached in two different ways: changing

only the type of fuel or changing the fuel and the technology for using it.

Various alcohol-gasoline blends have been used in different countries including Canada. Mohawk Oil Company is marketing such a mixture of gasoline and ethanol (gasohol) in Manitoba. This mixture can be used as a substitute for gasoline without modifying the vehicle engine or the distribution network. However, such a mixture is only an extender to the gasoline pool, not a true alternative fuel. Mixtures of up to 10 per cent ethanol and 90 per cent regular gasoline can readily be used but a greater percentage of ethanol would require engine modifications.

In Manitoba, gasohol is sold at a price competitive with gasoline but this results from a removal of the provincial gasoline tax on gasohol. Z. C. Slagorsky estimated in 1982 that this represents a 40¢/litre subsidy given for each litre of alcohol produced (and mixed with gasoline to obtain gasohol at 4¢/litre subsidy). Without this subsidy gasohol would not be competitive.[1]

In Manitoba Mohawk gasohol is sold at 15 retail outlets, but current ethanol output capacity accounts for only about 0.5 percent of Manitoba's 1980 gasoline usage and about 0.04 percent of Canadian gasoline usage in the same year. Slagorsky suggests that if Canada's 1980 level of gasoline consumption were to be extended by 10 percent with ethanol, current production capacity would have to be increased by a factor of 256.

Another possible alternative is methanol (wood alcohol) which can be used in a blend with gasoline and co-solvents, typically around 90 per cent gasoline with 5 percent of both methanol and co-solvents. Although Canada produces a significant amount of chemical grade methanol, Slagorsky suggests that extending the Canadian gasoline demand by 5 percent with methanol would require a doubling of 1982 total production capacity.[2]

Where new technology can be developed or utilized, many new and different types of fuels can be considered as alternatives. For transportation uses, new fuels may be

liquids such as 100 percent alcohol (either methanol or ethanol) or gaseous, such as compressed natural gas, propane or hydrogen. Electricity has also been studied as an alternative to gasoline and diesel fuels, at least in road, rail and pipeline transportation. At this point in time, however, most of these alternatives have failed to penetrate the transportation fuel market to a significant degree. Of the alternatives mentioned above, experts believe that the only viable alternatives in the short run, besides the gasohol already mentioned, are compressed natural gas and propane. In the case of methanol, its use may increase due to its octane boosting properties in gasoline blends.

CNG Fuel Systems of Calgary has several existing facilities to convert vehicles from gasoline to compressed natural gas (in Vancouver, Calgary, Toronto, and Montreal) and a greater number of CNG distribution outlets. At current prices of gasoline and CNG the substitution is economically viable with payback periods as short as one year, depending on the level of use and the type of vehicle. However, to date the number of conversions has been relatively small. At time of writing (Spring 1983), only 150 vehicle conversions had been made in Alberta and another 400 in British Columbia (estimates for Ontario and Quebec are at present unavailable). Conversion costs are about $2,350 which generate a 46 percent saving in operating costs.[3]

Propane was used as a motor fuel in 22,386 vehicles by May 6, 1983. The recent rate of conversions to propane was about 400 per week. Total estimates suggest that some 90,000 government and commercial vehicles could thus be powered by propane by 1990 in Ontario.[4]

Furthermore, there could be other conversions in the private vehicle sector, although probably not in the same numbers quoted above.

Hydrogen will likely be viable as a transportation fuel at some point in the future, but the technology for producing and using it on a large commercial scale is only in its infancy. Virtually no significant contribution from hydrogen is expected before the turn of the century.

Figure 6.1 gives recent cost estimates for the alternative transportation fuels. These are compared to conventional gasoline. The reader should keep in mind the fact that even though propane and CNG appear less expensive on an operating cost basis, there are significant conversion costs involved with any fuel other than gasoline or gasohol. Limited distribution systems for these fuels also imply that an imputed cost for inconvenience must also be considered.

Although only a small proportion of passenger cars in Canada use diesel fuel, a significant proportion of commercial and industrial trucks rely on this fuel because of its much lower cost per kilometer driven. Recently, passenger cars and light trucks have become available with diesel engines. While initial sales of these vehicles were encouraging, stagnating gasoline prices have greatly lowered the sales of diesel vehicles. The slowdown has been severe enough to cause the Chrysler Corporation to shelve plans for a diesel engine plant in Ontario.

The reader should note that various organic oils such as refined Canola can be substituted for diesel fuel with some modifications. This may at some point allow Prairie farmers to grow part of their own diesel requirements.

6.3 Residential Sector

Figures 6.2 and 6.3 show total off-oil conversions by energy form and region under the Canadian Oil Substitution Program (COSP).[5] The most interesting and surprising result was the number of wood conversions which occurred. In the fiscal year 1982-1983, 88,656 conversions to wood heat were made in Canada under COSP.[5] This was over 32.7 percent of all conversions made during that period. In the fiscal years 1981-1982 and 1982-1983, 122,708 conversions to wood have been made under the program.

In contrast, propane has accounted for only about 8,223 conversions in the two fiscal years under the COSP, or 1.6 percent. Conversions to other alternatives such as solar heat have been about the same at 8,374 or 1.7 percent of the total.

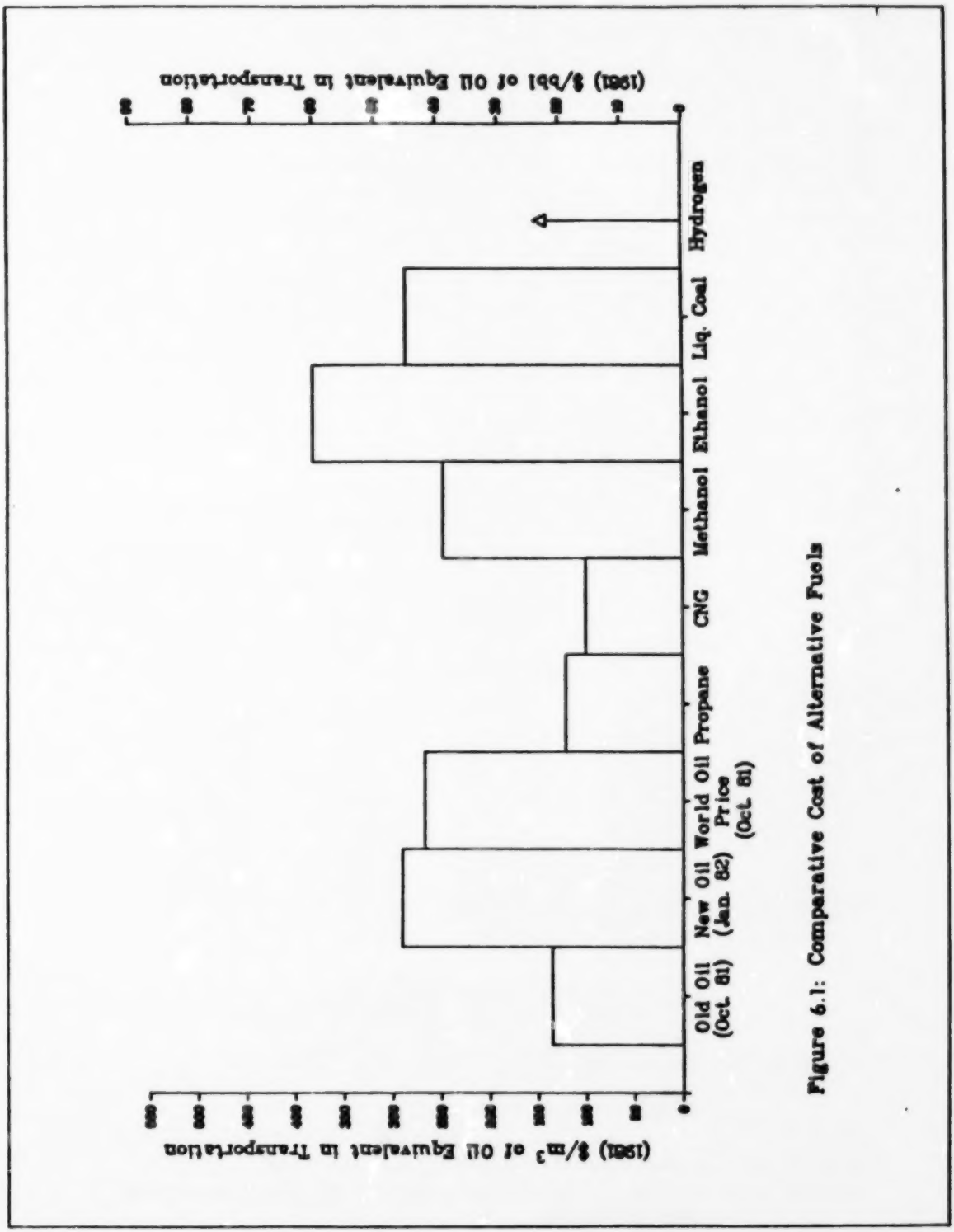
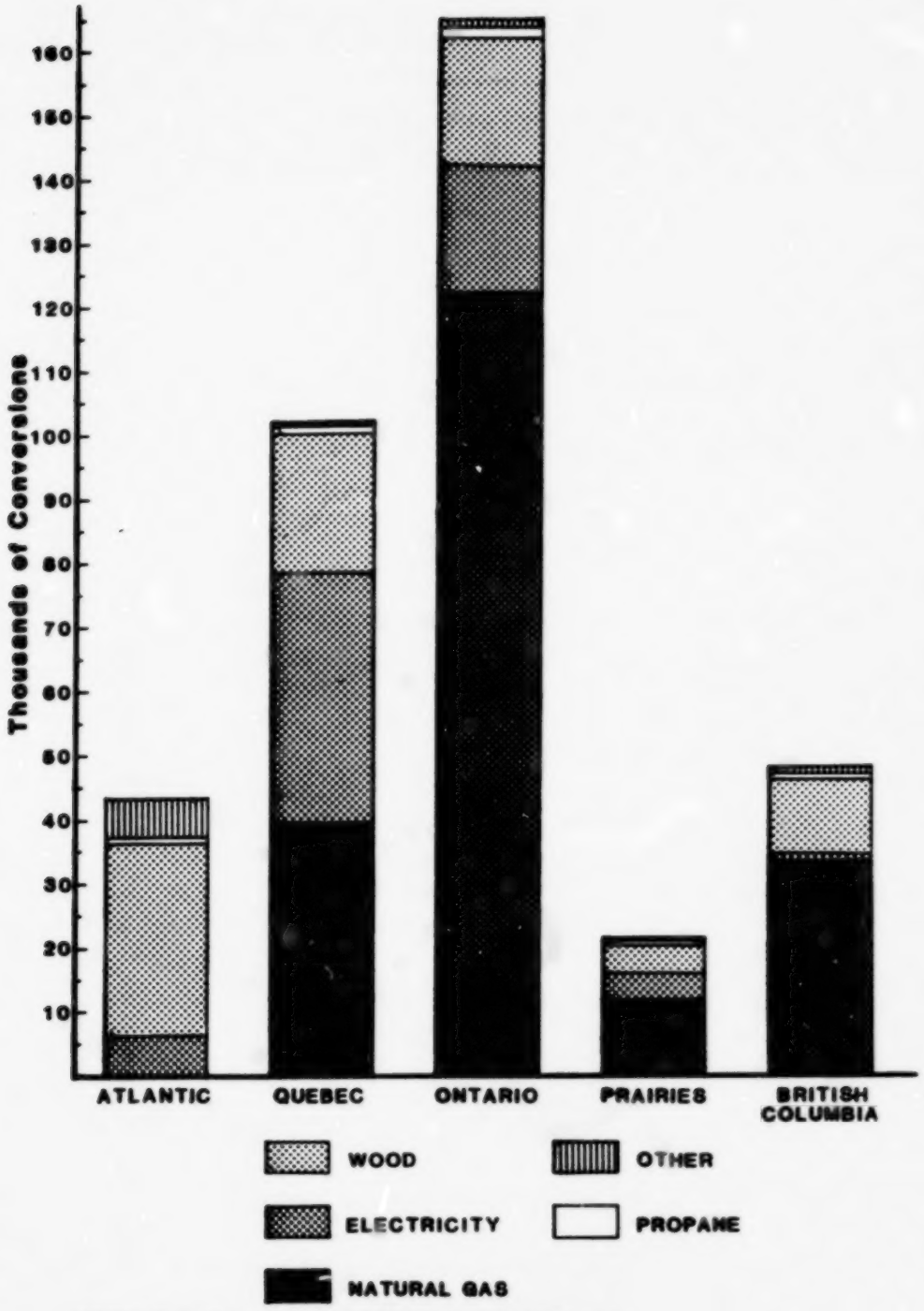
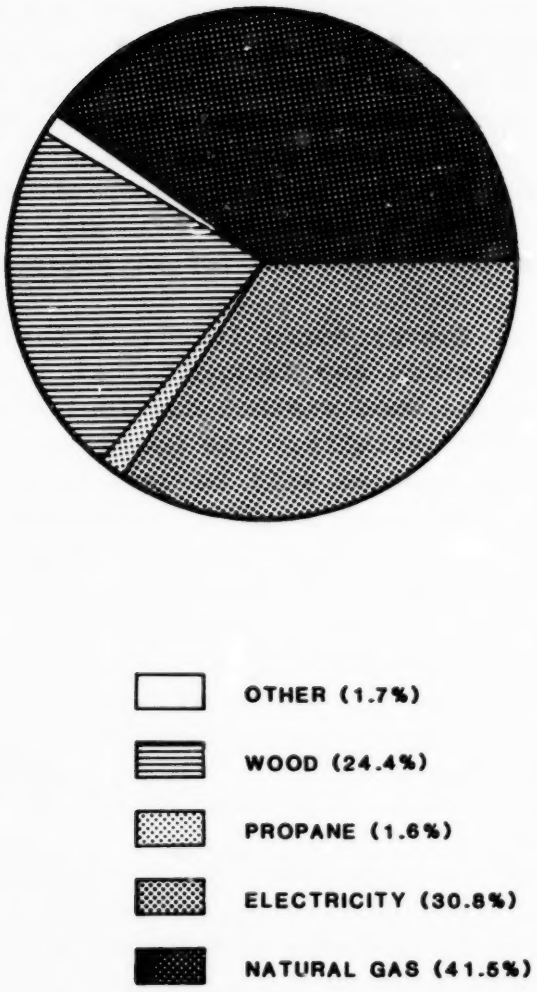


Figure 6.1: Comparative Cost of Alternative Fuels



NOTE: For fiscal years 1981-82 and 1982-83
SOURCE: Energy, Mines and Resources Canada, July 1983.

FIGURE 6.2: TOTAL COSP CONVERSIONS BY ENERGY TYPE AND REGION



NOTE: For fiscal years 1981-82 and 1982-83.

FIGURE 6.3: TOTAL COSP CONVERSIONS-CANADA

Because of the relatively high cost associated with installing solar systems and other risks, few homeowners have opted for this type of heat (other category). However, as the housing stock turns over it can be expected that more and more housing designs will make use of solar features which do not require great capital outlays for new houses.

6.4 Commercial-Industrial Sector

Most of the unconventional alternatives to oil, gas, coal or electricity have not found their way into the commercial-industrial sector in large proportions. However, hog fuel (basically mill wood wastes) and spent pulping liquor are used as fuel within the forest products industry.

The National Energy Board forecasts that, because of rising oil and gas prices and technological improvements in boilers designed to use wood wastes, hog fuel and pulp liquor use will increase substantially. The Board projects that 381 petajoules and 448 petajoules will be used in 1985 and 1990, respectively. This reflects an average growth rate of 3.5 percent per year.[6] It was expected that these fuels would be most important in British Columbia, Quebec, Ontario, and the Atlantic provinces and would displace mainly heavy fuel oil. By 2000 these two renewable fuels are expected to contribute 3.5 percent of primary energy.

6.5 Potential Contributions of New Alternatives

Of the many new alternatives to conventional and historically used fuels, such as solar energy, wind energy, wave energy and others, the NEB forecasts that 9 petajoules (net of hog fuel and pulping liquor) will come from these sources in 1985 and 87 petajoules in 1990. The average annual growth rate over the 1980-1990 period is expected to be 27 percent. Using these estimates, this amount represents 0.0068 percent of total primary energy demand in 1990.[7]

Although this is not a large proportion, it is useful because it demonstrates that the alternatives are technologically and economically viable, given certain conditions.

There is little doubt that conventional petroleum products, natural gas, coal, and electricity will remain prominent in Canada's energy markets until well into the twenty-first century. However, the knowledge that supplies of oil, gas and coal are finite makes the long-run substitution of alternatives imperative. An early introduction of these energy forms into energy markets should make eventual large scale reliance less painful. As the alternatives become economically viable, their substitution may be the lowest cost solution to meeting energy needs.

Footnotes

[1]Charles Slagorsky, Alternative Transportation Fuels in Canada, Study No. 16 (Calgary: Canadian Energy Research Institute, July 1982), p. 48.

[2]Ibid., p. 78.

[3]CNG Fuel Systems Ltd., personal communication with Calgary office.

[4]Slagorsky, p. 85.

[5]Canada, Energy, Mines and Resources Canada, Canadian Off-oil Substitution Program.

[6]Canada, National Energy Board, Canadian Energy, Supply and Demand, 1980-2000 (Ottawa: Supply and Services Canada, June 1981), p. 28.

[7]Ibid.

Chapter 7

SUMMARY

One major objective of the National Energy Program was to reduce consumption of oil to no more than 10 percent of total energy use in the non-transportation sectors of the economy. The historical review in Chapter 3 has shown that to meet this objective considerable substitution would have to occur because oil represents almost 27 percent of industry's energy needs, 25 percent of commercial sector energy use and almost 45 percent of residential energy use.

7.1 Conventional Fuels - The National Perspective

In Chapter 4 estimates of inter-fuel substitution likely to occur, given certain pricing assumptions, were provided. On the national level it was shown that under the most likely oil price scenario, consumption of crude oil is projected to fall only enough to reduce oil's total market share by 3 percent between 1985 (33 percent) and 1990 (30 percent). The declining oil share is picked up by natural gas which rises from 33 percent in 1985 to 36 percent in 1990. Both the electricity and the coal share of energy demand remain static over the same period, at 27 and 7 percent, respectively, indicating no net substitution towards these sources of energy. The higher oil price scenario (although it reduces oil demand slightly) does not change the crude oil market share. Furthermore, under the lowest oil price scenario crude oil loses only 2 percent of its market share by 1990, while natural gas gains 5 percent (at the expense of oil, electricity and coal).

The results reported here indicate that inter-fuel substitution will continue to occur as the decade progresses. However, they also suggest that it is unrealistic to expect that the NEP goal can be achieved given the softening in world oil prices, and in their expected path, since 1981.

Chapter 5 presented the results of simulations run with the ceiling on old oil prices removed. These simulations revealed that oil consumption was reduced by a further 2.5 percent (in comparison to the base case) in 1985 and 2 percent lower in the year 1990. However, such reductions in demand for oil are not large enough to cause a significant movement in energy market shares. It would appear that oil prices would have to rise considerably above the levels projected in Chapter 5 to lower the market share of oil to a much greater extent.

While the NEP set a maximum usage goal for crude oil (10 percent in three sectors) it also set goals for minimum use of gas, electricity, coal and renewable forms of energy. The 'most likely' price scenario simulation undertaken indicates reliance on natural gas to be ahead of the NEP Update projections. However, both electricity and coal are forecast by the Mace model simulations to be less important in terms of their energy market shares than in the NEP. The NEP Update forecast reliance on primary electricity to be 32.7 percent by 1990 and reliance on coal to be 10.3 percent. The Mace forecasts show 27 percent reliance on electricity and only a 7 percent reliance on coal by 1990. This result is not surprising in light of the much lower oil and gas price scenarios used in the Mace simulations. Lower prices for oil and gas will tend to slow down substitution of coal and electricity.

7.2 Renewable Energy

The Mace model does not have renewable energy forms incorporated into its structure. There is, therefore, no model estimate as to how much penetration one might expect from these sources. The NEP estimate is that by 1990 renewables will account for 6 percent of total primary energy use, but the National Energy Board has projected that less than 1 percent will come from these sources.[1] Some estimate as to how reliable the NEP forecast for renewable penetration is might be obtained from the latest estimate of conversions made under the COSP by Energy, Mines and Resources Canada. In fiscal years 1981-1982 and 1982-1983, 98,610 conversions were made to wood heat, solar heat, or other renewable forms of energy. This number is considerably above the most recent

program forecast of 45,900 conversions and the older NEP forecast of 56,960 conversions. It is encouraging that actual conversions were almost double the forecast numbers. However, it is uncertain whether future levels of conversions can be maintained at this level due to growing saturation in the retrofit market.

As might be expected these renewable conversions were largely made in those provinces where wood is abundant around population centers: Nova Scotia, Quebec, Ontario and British Columbia.

7.3 Regional Trends in Conventional Substitution

As noted in Chapter 3, energy use differs greatly across Canada by region depending upon the indigenous supplies and the transportation facilities in place. Similarly, inter-fuel substitution potential varies greatly across Canada.

The simulations revealed that very little substitution would take place in Atlantic Canada among oil, electricity and coal. In fact, from 1985 to 1990 only 1 percent of oil's total usage shifts to coal. This scenario belies the fact that, although conversions to renewable energy are occurring in this area, the absence of the natural gas alternative and the generally high cost of electricity will tend to keep oil prominent well into the future. Atlantic Canada will, of course, eventually have access to both Hibernia oil and Sable Island natural gas.

Quebec is still heavily reliant on oil (45 percent), but unlike any other region also has a large dependence on electricity (42 percent). The model simulations suggest that oil will lose its prominence only slightly (1 percent). The 1 percent share lost by oil is gained by natural gas not electricity. However, the most recent COSP reports indicate that during 1982 to 1983, conversions to electricity (32,000) totalled more than three times the number of conversions to natural gas (10,023). Conversions to other sources of heat numbered almost 23,000 in Quebec during the period. Most of these would have been to wood heat. It must be remembered

that natural gas distribution in Quebec is still somewhat limited.

The inter-fuel substitution simulation results are more encouraging in Ontario where oil loses 4 percent of its share to gas over the 1985 to 1990 period under scenario number 2. Under oil price scenario 3, natural gas gains 5 percent. These results are supported by the COSP figures for 1982 to 1983 which show 37,600 conversions to gas, twice as many conversions as those to electricity. Well-developed gas distribution systems in Ontario would contribute to the ease of conversion.

On the Prairies natural gas is the most important fuel and will continue to gain prominence between 1985 and 1990. Gas gains 2 percent of the market at the expense of oil. Electricity does not add to its share over the period. The relatively small usage of oil on the Prairies (as a percentage of total energy) suggests that transportation is the only sector where oil is of primary importance. But Figure A.11 shows that oil was still important in the residential sector (this is especially true in Saskatchewan). However, conversions to gas in all three provinces, to electricity mainly in Manitoba and to wood mainly in Saskatchewan, will tend to eventually confine oil use to the transportation sector.

British Columbia, as all other regions west of Quebec, relies heavily on natural gas. Simulations with the Mace model show that this reliance will increase by about 3 percent of the total energy market between 1985 and 1990. This expanded market share results from slower expansion of both oil and electricity. Oil's share falls by 1 percent over the period.

Recent estimates of conversions under the COSP program in British Columbia reveal that about 68 percent of conversions have been to natural gas and only a very small (4 percent) proportion to electricity. About 27 percent of conversions have been to wood heat and 2 percent to propane.

In the Northwest Territories and the Yukon Territory conversions to wood heat, propane and other renewable forms have been significant.

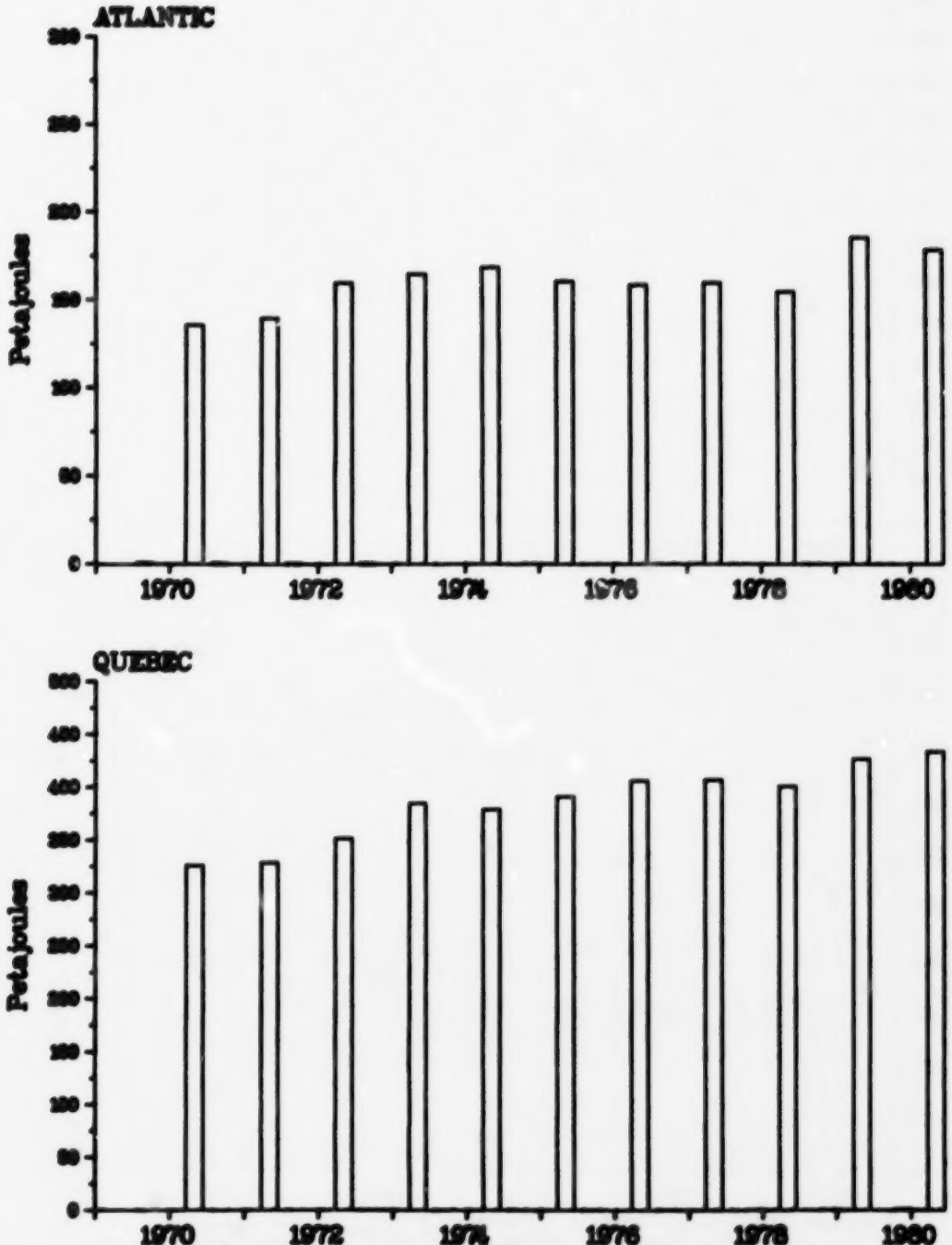
The results reported here show that inter-fuel substitutions are occurring in all regions of Canada but in different numbers due to the unique energy supply/price conditions in each region. It is expected that off-oil conversions will continue as oil remains the most expensive form of heating in most areas of Canada. If international oil prices begin to rise again sooner than predicted here, substitution away from oil would be more pronounced than suggested by this analysis.

Footnotes

[1]Canada, National Energy Board, Canadian Energy, Supply and Demand, 1980-2000 (Ottawa: Supply and Services Canada June 1981), p. 28.

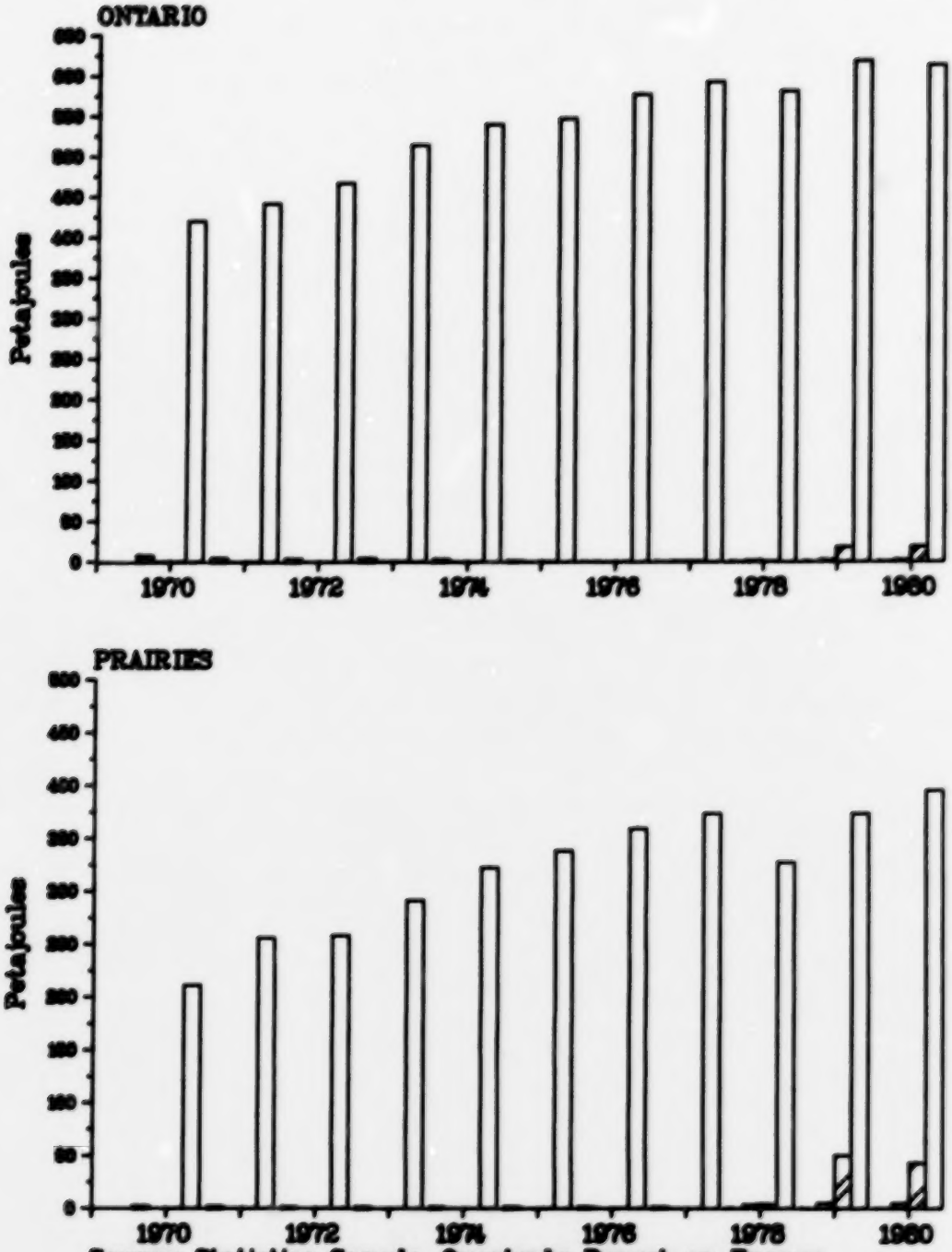
APPENDIX A

HISTORICAL ENERGY CONSUMPTION IN CANADA



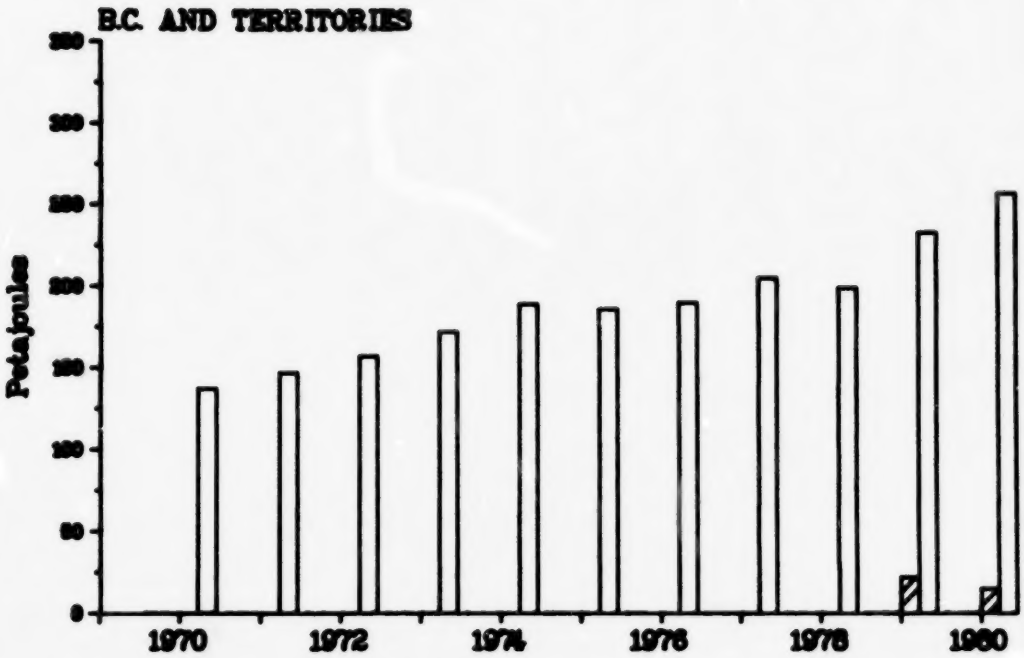
Source: Statistics Canada, Quarterly Report on Energy Supply/Demand in Canada, 57-003 and Detailed Energy Supply and Demand in Canada, 57-207.

Figure A.1: Energy Use in the Transportation Sector, Atlantic Canada and Quebec



Source: Statistics Canada, Quarterly Report on Energy Supply/Demand in Canada, 57-003 and Detailed Energy Supply and Demand in Canada, 57-207.

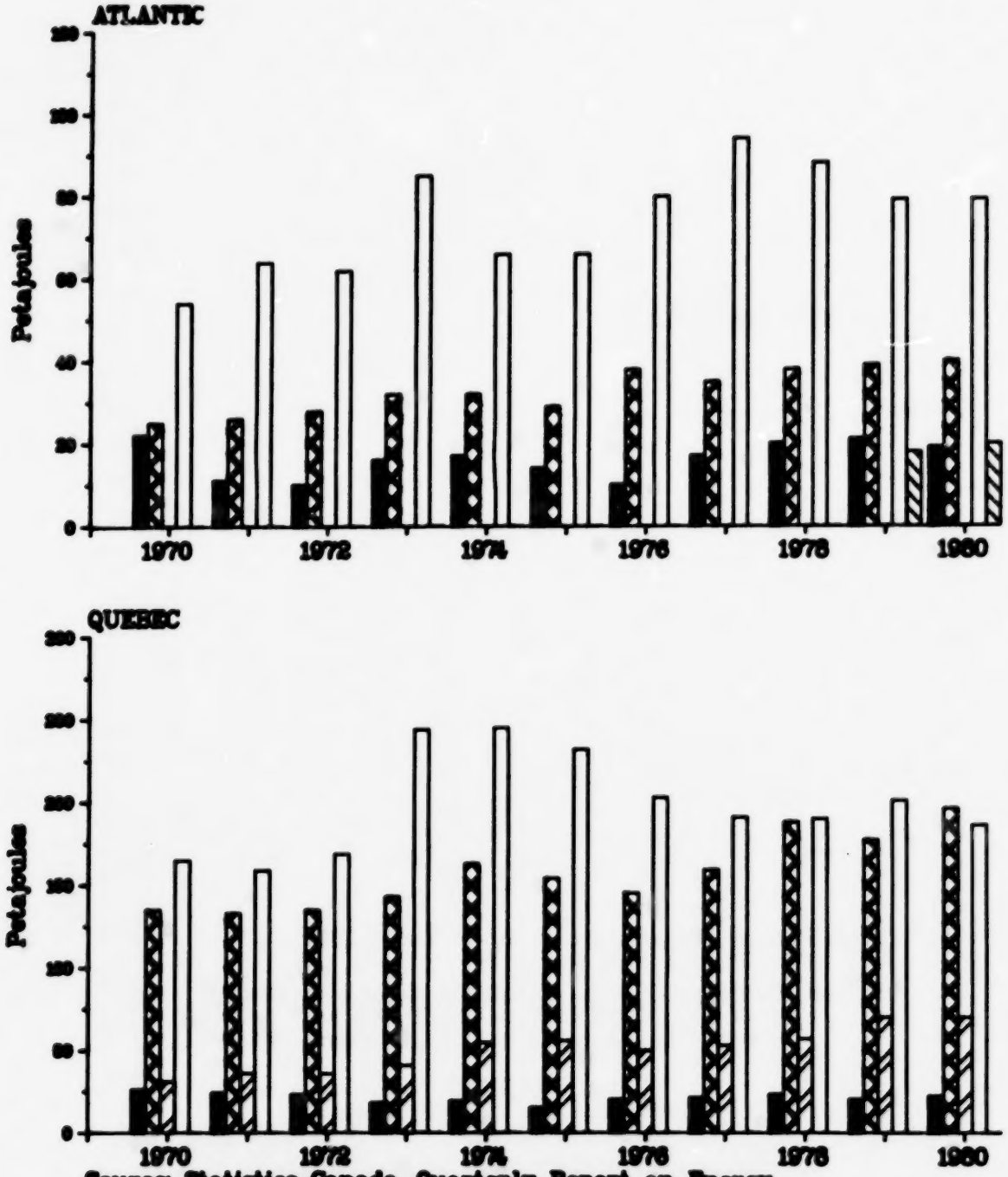
Figure A.2: Energy Use in the Transportation Sector, Ontario and the Prairies



Note: Natural gas use shown in 1979 and 1980 was for pipeline fuel only.

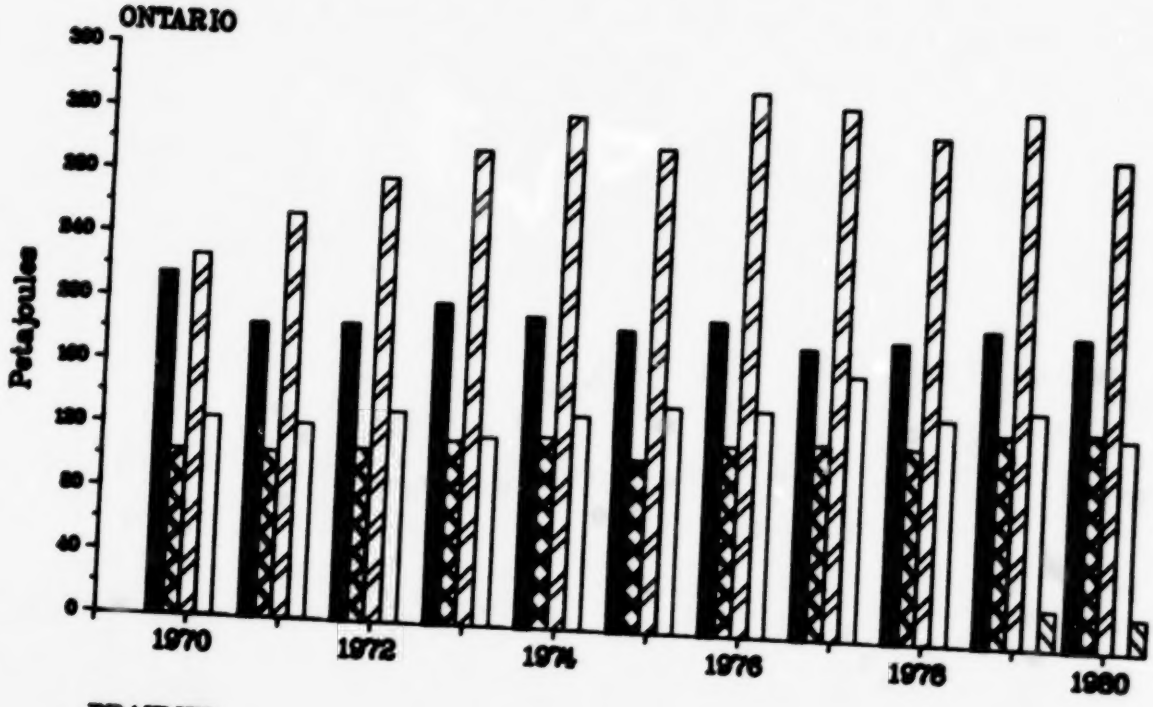
Source: Statistics Canada, Quarterly Report on Energy Supply/Demand in Canada, 57-003 and Detailed Energy Supply and Demand in Canada, 57-207.

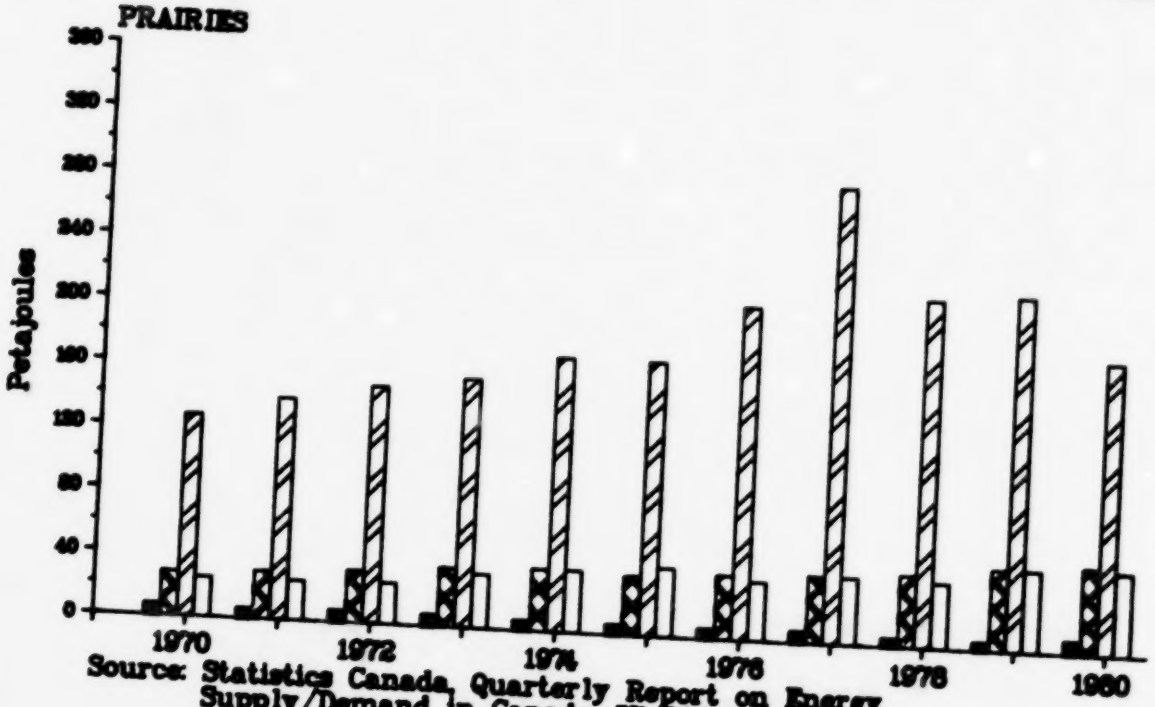
Figure A.3: Energy Use in the Transportation Sector, B.C. and the Territories



Source: Statistics Canada, Quarterly Report on Energy Supply/Demand in Canada, 57-003 and Detailed Energy Supply and Demand in Canada, 57-207.

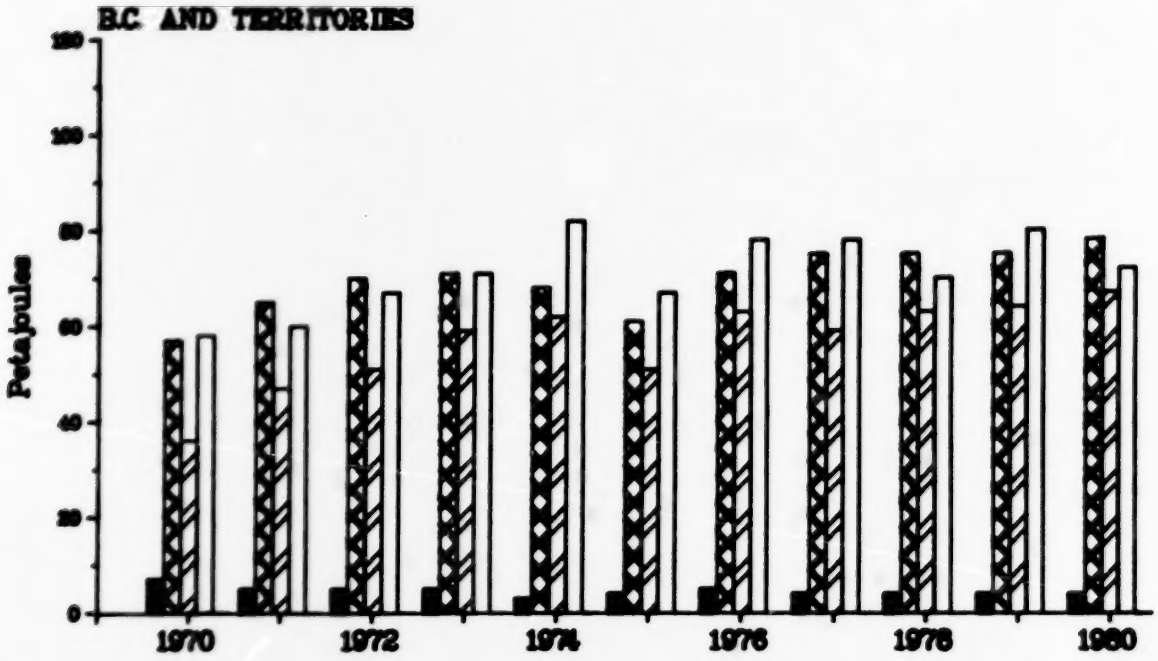
Figure A.4: Energy Use in the Industrial Sector, Atlantic Canada and Quebec





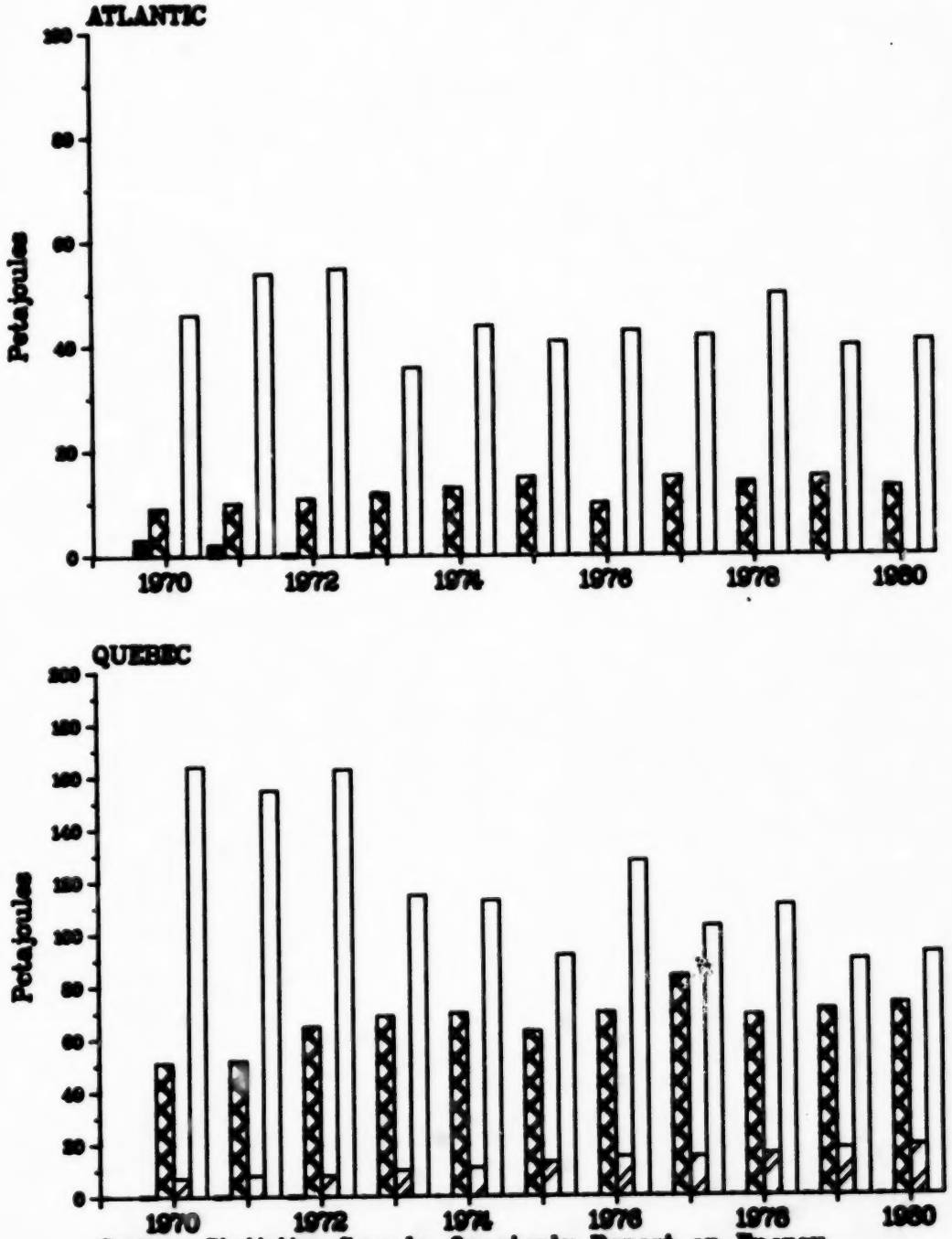
Source: Statistics Canada, Quarterly Report on Energy Supply/Demand in Canada, 57-003 and Detailed Energy Supply and Demand in Canada, 57-207.

Figure A.5: Energy Use in the Industrial Sector, Ontario and the Prairies



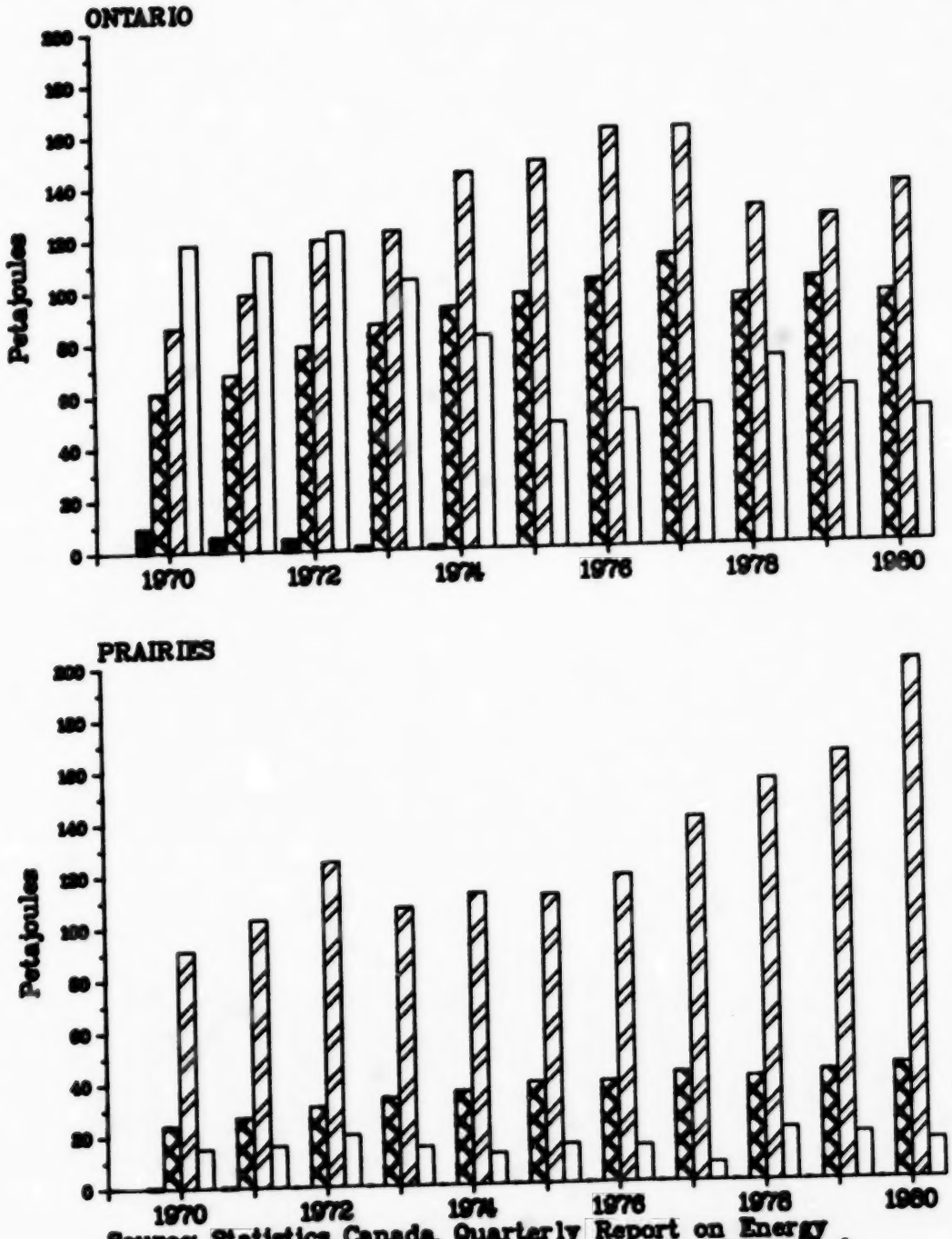
Source: Statistics Canada, Quarterly Report on Energy Supply/Demand in Canada, 57-003 and Detailed Energy Supply and Demand in Canada, 57-207.

Figure A.6: Energy Use in the Industrial Sector, B.C. and the Territories



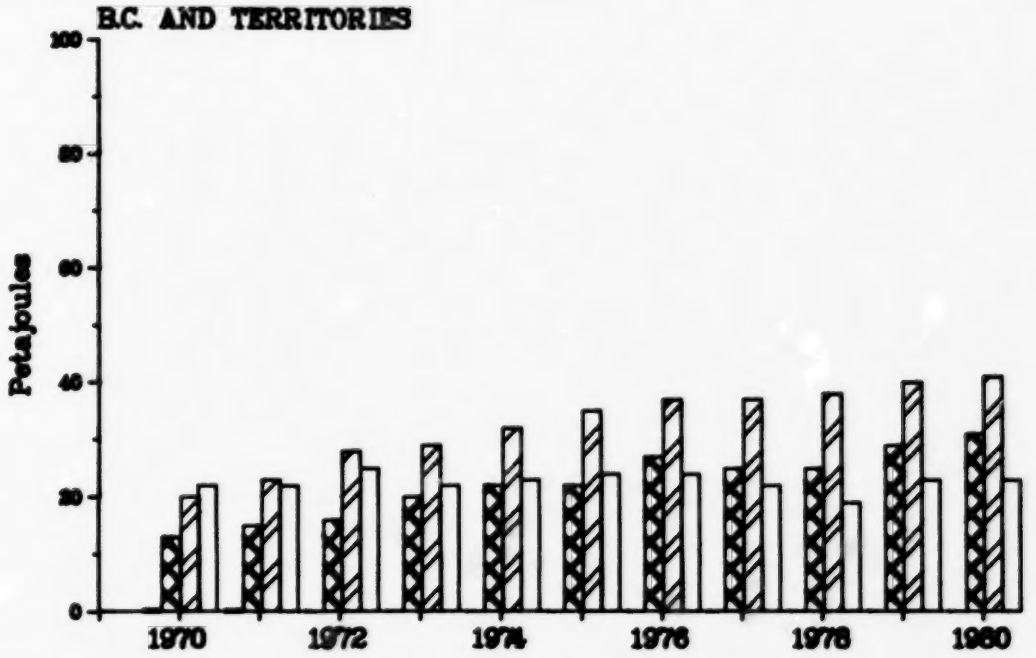
Source: Statistics Canada, Quarterly Report on Energy Supply/Demand in Canada, 57-003 and Detailed Energy Supply and Demand in Canada, 57-207.

Figure A.7: Energy Use in the Government – Commercial Sector, Atlantic Provinces and Quebec



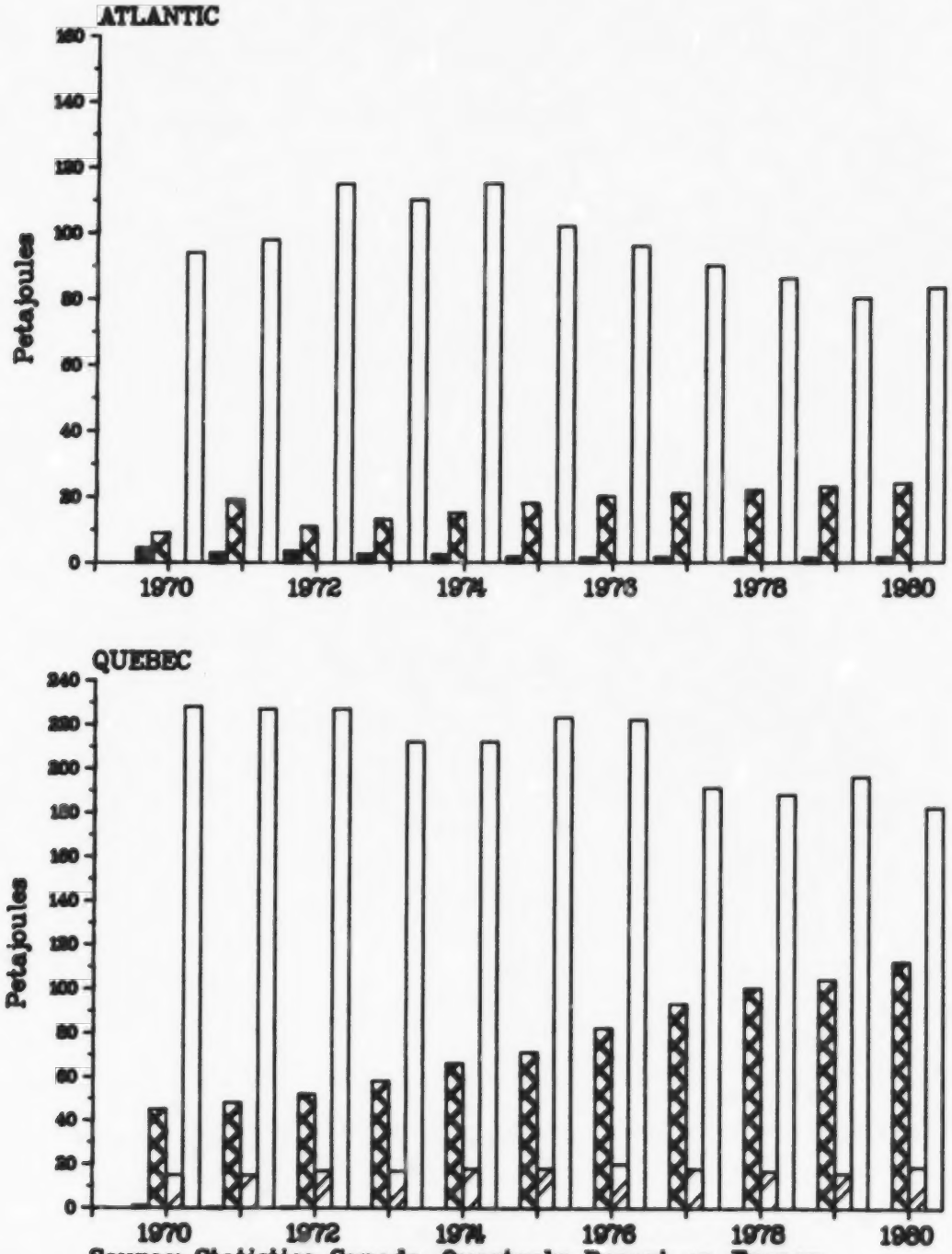
Source: Statistics Canada, Quarterly Report on Energy Supply/Demand in Canada, 57-003 and Detailed Energy Supply and Demand in Canada, 57-207.

Figure A.8: Energy Use in the Government – Commercial Sector, Ontario and the Prairies



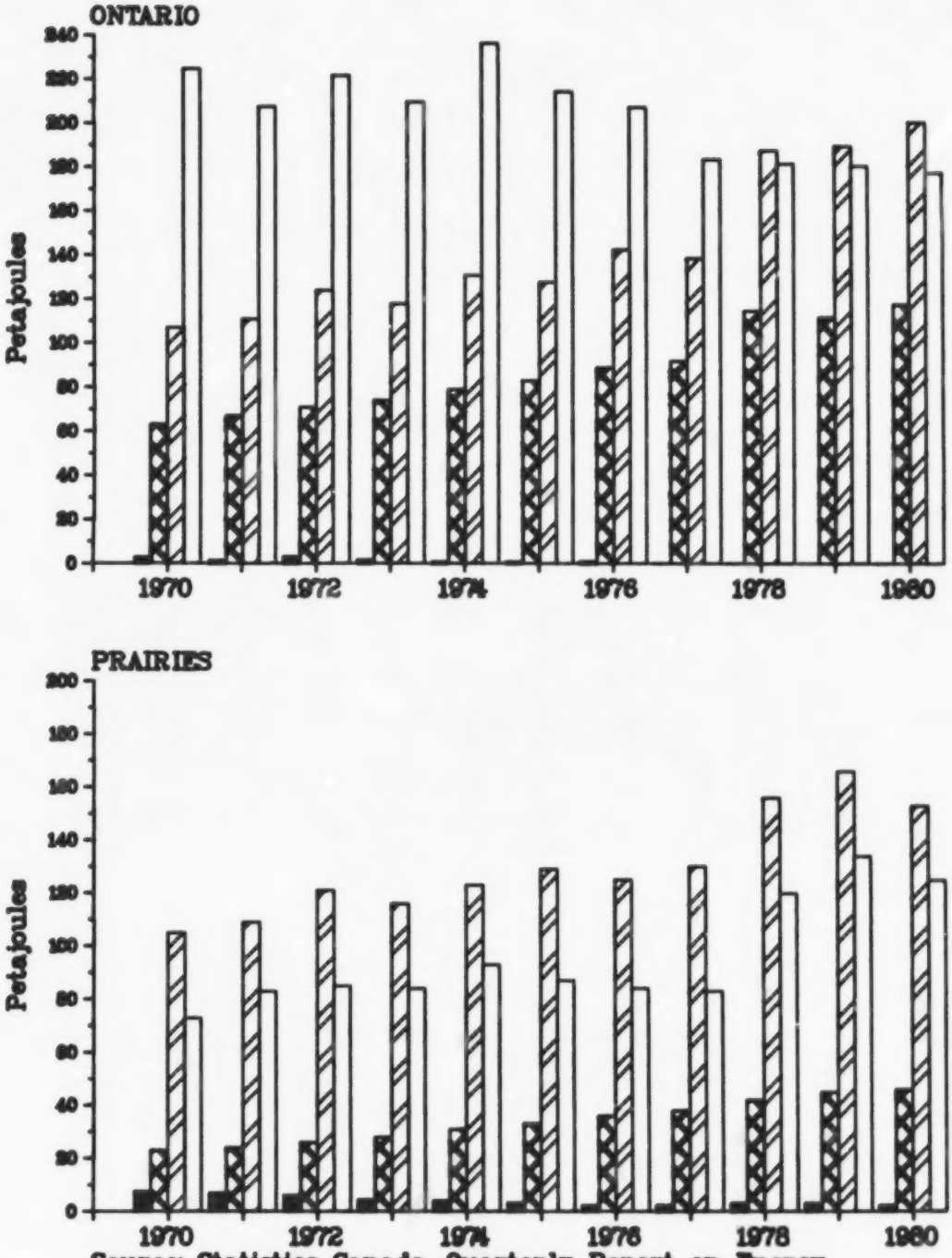
Source: Statistics Canada, Quarterly Report on Energy Supply/Demand in Canada, 57-003 and Detailed Energy Supply and Demand in Canada, 57-207.

Figure A.9: Energy Use in the Government - Commercial Sector, B.C. and the Territories



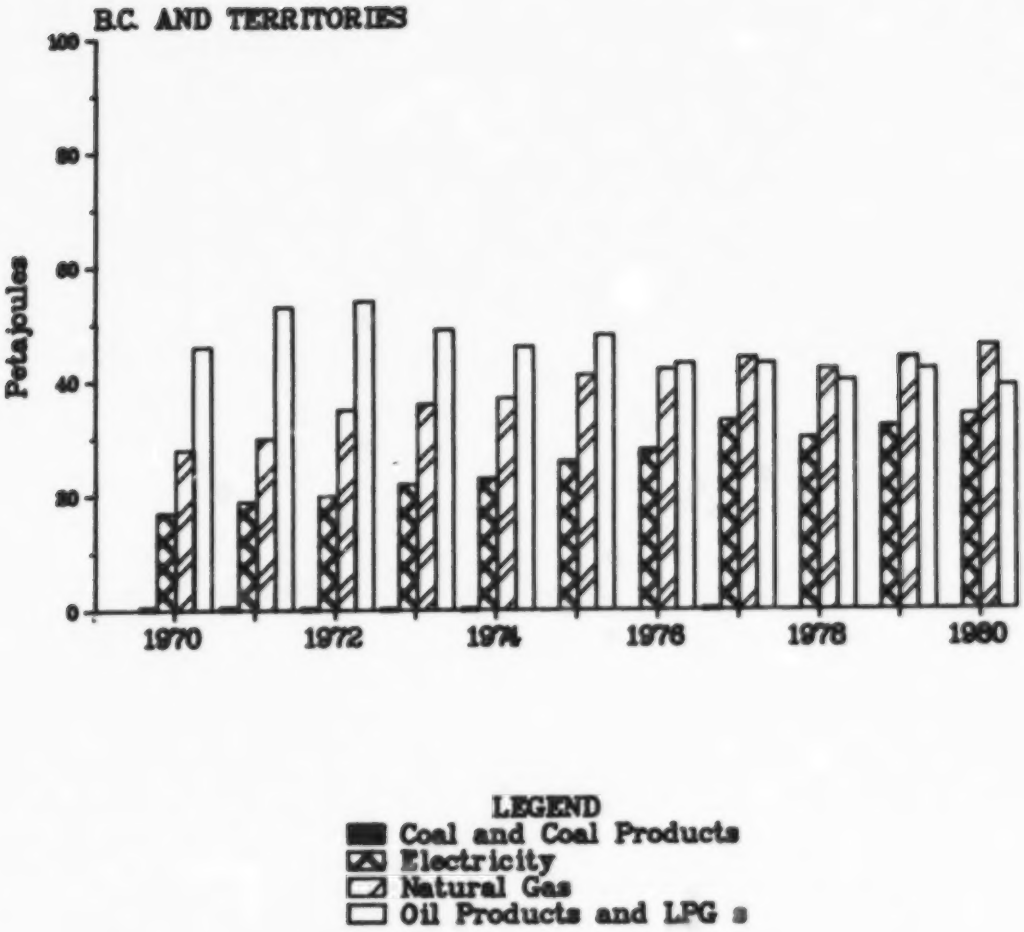
Source: Statistics Canada, Quarterly Report on Energy Supply/Demand in Canada, 57-003 and Detailed Energy Supply and Demand in Canada, 57-207.

Figure A.10: Energy Use in the Residential – Farm Sector, Atlantic Provinces and Quebec



Source: Statistics Canada, Quarterly Report on Energy Supply/Demand in Canada, 57-003 and Detailed Energy Supply and Demand in Canada, 57-207.

Figure A.11: Energy Use in the Residential - Farm Sector, Ontario and the Prairies



Source: Statistics Canada, Quarterly Report on Energy Supply/Demand in Canada, 57-003 and Detailed Energy Supply and Demand in Canada, 57-207.

Figure A.12: Energy Use in the Residential - Farm Sector, B.C. and the Territories

APPENDIX B

Btu EFFICIENCY CONVERSION FACTORS

Appendix B

Btu EFFICIENCY CONVERSION FACTORS

The Btu conversion factors have been obtained from the introduction to the Statistics Canada document, Detailed Energy Supply and Demand in Canada. For electricity the conversion factor is 3.412 million Btu/1000 kW.h; for natural gas the conversion factor is approximately 1.0 million Btu/Mcf; for crude oil the conversion factor is 5.803 million Btu/bbl; for coal the conversion factor varies over time and by region because different types of coal have different factors.

The conversion factors shown in Table B.1 have been used in Mace to determine output energy from input energy supplied. The process of conversion of energy supplied into useful energy by various types of equipment is usually less than 100 percent efficient, with the exception of resistance heating by electricity. For example, the conversion efficiency factor for motor gasoline in the road transportation sector is about 0.20 or 20 percent. This means that if 1 million joules of energy in the form of gasoline are burned in a vehicle only 1,000,000 x 0.20 = 200,000 joules are actually converted into useful energy (i.e., vehicle movement).

TABLE B.1

UTILIZATION EFFICIENCY FACTORS
ACROSS ALL END-USE SECTORS
(proportion)

	Res.	Com.	Ind.	Trans. Road	Trans. Rail	Trans. Air	Trans. Marine
Coal	0.50	0.65	0.87	-	0.08	-	0.08
LPG	0.75	0.78	0.85	-	-	-	-
Still gas	-	-	0.85	-	-	-	-
Kerosene	0.55	0.82	0.82	-	0.55	-	0.55
Diesel oil	0.23	0.23	0.26	0.23	0.23	-	0.15
Light fuel oil	0.65	0.82	0.82	-	0.82	-	0.10
Heavy fuel oil	0.80	0.80	0.87	-	0.80	-	0.10
Motor gasoline	-	-	-	0.20	-	-	-
Aviation gasoline	-	-	-	-	-	0.20	-
Aviation turbofuel	-	-	-	-	-	0.30	-
Natural gas	0.75	0.78	0.85	-	-	-	-
Electricity	1.00	1.00	1.00	-	-	-	-

Where: Res. is used to represent the residential sector,
Com is used to represent the commercial sector,
Ind. is used to represent the industrial sector,
Trans. is used to represent the transportation sector.

SOURCE: Statistics Canada, Detailed Energy Supply and Demand in Canada, Catalogue 57-203 and University of British Columbia, UBC Integrated Energy Model.

APPENDIX C

ESTIMATED ELASTICITIES

TABLE C.1

ESTIMATED 5-YEAR CITY-GATE PRICE ELASTICITIES
FOR FUELS IN CANADA

	Oil	Gas	Electricity
P Oil	-0.506	0.0490	-0.119
R I Gas	+0.135	-0.615	-0.0033
C E Electricity	-0.0640	-0.0203	-0.426

TABLE C.2

ESTIMATED 5-YEAR USER PRICE ELASTICITIES
FOR FUELS IN CANADA

	Oil	Gas	Electricity
P Oil	-0.656	0.0635	-0.154
R I Gas	+0.153	-0.699	-0.0038
C E Electricity	-0.0640	-0.0203	-0.426

SOURCE: John F. Helliwell, et al, Energy and the National Economy, an Overview of the Mace Model, Department of Economics Resource Paper 89 (Vancouver: University of British Columbia, March 1983).

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